CARROLL COUNTY STATION

INSTRUCTIONS FOR UPDATING YOUR SITE SUITABILITY-ENVIRONMENTAL REPORT REVISION 2 - 8/79

Changes to the Environmental Report are identified by a vertical line in the right margin of the page. To update your copy of the CCS-SS-ER, remove and destroy the following pages and figures and insert pages and figures as indicated.

REMOVE	INSERT
VOLUME 1	
Findings	
Pages 1 and 2	Pages 1 and 2
Chapter 1	
Pages 1.0-i through 1.0-ix	Pages 1.0-i through 1.0-ix
Section 1.1	
Pages 1.1-1 through 1.1-54 Figures 1.1-10 and 1.1-11	Pages 1.1-1 through 1.1-57 Figures 1.1-10 and 1.1-11
Section 1.2	
Page 1.2-1	Page 1.2-1
Section 1.3	
Page 1.3-1	Page 1.3-1
Section 1.4	
Pages 1.4-1 through 1.4-18 Figure 1.4-4	Pages 1.4-1 through 1.4-19 Figure 1.4-4
Appendix 1.4B	
Page 1.4B-3	Page 1.4B-3
Section 1.7	
Pages 1.7-1 through 1.7-21	Pages 1.7-1 through 1.7-23

REMOVE	INSERT
VOLUME 1 (Continued)	
Section 1.8	
Page 1.8-1	Page 1.8-1
Section 1.9	
Page 1.9-1	Page 1.9-1
Chapter 2	
Section 2.1	
Pages 2.1-4 and 2.1-5 Figure 2.1-5	Pages 2.1-4 and 2.1-5 Figure 2.1-5
VOLUME 2	
Section 2.6	
Pages 2.6-7 through 2.6-10	Pages 2.6-7 through 2.6-10
Chapter 4	
Section 4.1	
Figure 4.1-1	Figure 4.1-1
VOLUME 3	
Chapter 8	
Section 8.1	
Pages 8.1-1 through 8.1-3	Pages 8.1-1 through 8.1-3

Proposed Findings on the
Issues of Site Suitability on Which
Commonwealth Edison Company is Requesting Review

Background

1) Commonwealth Edison Company (CECo), as Applicant, has requested early site review leading to construction permits and operating licenses in accordance with the United States Nuclear Regulatory Commission's (NRC) promulgated regulations regarding early site review, "Early Site Reviews and Limited Work Authorizations", as published May 5, 1977, 42 Federal Register 22882-22888, effective June 6, 1977.

2) The ownership of Carroll County Nuclear Generating Station, Units 1 and 2 will be: "Commonwealth Edison Company - 75%; Interstate Power Company - 10%; Iowa - Illinois Gas and Electric Company - 15%." Commonwealth Edison Company will be responsible for the design, licensing, construction and operation of the Carroll County Station, Units 1 and 2. 1

3) Applicant's information in support of its early site review application consists of the License Application: Carroll County Station - Site Suitability - Site Safety Report (CCS-SS-SSR) which has been prepared in accordance with Chapter 2 of NRC Regulatory Guide 1.70, Revision 2; and the Carroll County Station - Site Suitability - Environmental Report (CCS-SS-ER) which includes portions of chapters 1, 2, 3, 4, 5, 6, 8, 9, 12 and 13 prepared in accordance with NRC Regulatory Guide 4.2, Revision 2.

4) Early site review was requested for construction and operation of two pressurized water reactor (light water) units of up to 3500 Mw(t) each and of the general type recently approved for construction and currently under review for construction by the NRC. Specific aspects of site and facility design and operating parameters sufficient to enable the NRC to perform the requested review of site suitability issues under the applicable provisions of 10 CFR Parts 50, 51 and 100 and the bases for the proposed findings were presented together with the corresponding findings.

5) The Applicant's site selection analysis is described in CCS-SS-ER Section 9.2 and is discussed in paragraphs 137 and 138.

6) The Carroll County Site is considered capable of supporting these two proposed nuclear power units of up to 3500 Mw(t) of the general type currently being licensed in the United States.

7) A partial initial decision on the proposed issues of site suitability is in the public interest so that these issues may be resolved in a timely manner.

8) The utilities that will be the owners of the proposed Carroll County Station, Units 1 and 2 have demonstrated future need for their proportionate share of the power output, which will necessitate the filing of the remainder of the construction permit within the five years of the issuance of the Early Site Review findings (CCS-SS-ER Chapter 1.0). 2

Site Suitability and Safety Matters

9) The Applicant has satisfactorily identified the location of the Carroll County site as it pertains to political subdivisions and prominent natural and man-made features. Site location information is summarized below:

10) The 3,490-acre Carroll County Station site is located in northwestern Illinois, 4.5 miles southeast of the city of Savanna and 2.7 miles east of the Mississippi River in Carroll County. The Illinois-Wisconsin border is located 35 miles to the north. U.S. Route 52/Illinois State Route 64 is the closest major highway to the site and its closest point of approach is 3.5 miles north-northeast of the Carroll County Station. Other principal roads in the area are Illinois State Routes 84 and 78, located 2.2 miles west-southwest and 3.1 miles southeast of the site, respectively. (CCS-SS-ER § 2.1 and CCS-SS-SSR § 2.1)

11) The Applicant has satisfactorily specified the exclusion and restricted areas for the Carroll County Station. The exclusion area will be located entirely within the site boundary **and have an area of approximately 644 acres. The minimum exclusion boundary distance from the gaseous release point is approximately 2040 feet (622 meters) as measured from the surface of Unit 1 containment. Although there are at present several residential structures and one commercial operation onsite, none of these are located within the proposed exclusion area. No public highways, waterways or railroads traverse the proposed exclusion area.** 1 **The** restricted area boundary for the Carroll County Station is coincident with exclusion area boundary. Both the exclusion area and the restricted area meet the guidelines of 10 CFR Part 100 and 10 CFR Part 20, respectively (CCS-SS-ER §2.1 and CCS-SS-SSR §2.1). 2

12) The Applicant has satisfactorily located and described all significant industrial, transportation, and military facilities. The Applicant has also described, using available data, the products and materials regularly manufactured, stored, used or transported in the site vicinity. A summary of major facilities is given below:

Revision 1 5/79
Revision 2 8/79

902073

CHAPTER 1.0 - PURPOSE OF THE PROPOSED FACILITY AND ASSOCIATED TRANSMISSION

TABLE OF CONTENTS

2

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

CHAPTER 1.0 - PURPOSE OF THE PROPOSED FACILITY AND ASSOCIATED TRANSMISSION

LIST OF TABLES

2

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

LIST OF TABLES (Continued)

2

902080

CHAPTER 1.0 - PURPOSE OF THE PROPOSED FACILITY AND ASSOCIATED TRANSMISSION

LIST OF FIGURES

2

LIST OF FIGURES (Continued)

CHAPTER 1.0 PURPOSE OF THE PROPOSED FACILITY AND ASSOCIATED TRANSMISSION

1.1 SYSTEM DEMAND AND RELIABILITY - COMMONWEALTH EDISON COMPANY

This section discusses the need for the Carroll County nuclear units in Commonwealth Edison Company's (CECo) system. As CECo is not a member of any power pool, planning studies are based on the load and capacity characteristics of the CECo system.

CECo is a member of the Mid-America Interpool Network (MAIN), one of the nine reliability councils in the country.

Additional generating capacity is required for three reasons. The first is to meet the increased load caused by load growth. Second, new capacity is required to replace old generating equipment retired because of obsolescence or environmental considerations. Third, new capacity is needed to meet the increased reserve requirements caused by the added load.

The capacity of CECo for the summer of 1978 was as follows: 2

Nuclear	5,058 MW	
Base Fossil	6,517	
Cyclical Fossil	3,344	2
Fast Start Peaking Units	1,879	
TOTAL:	16,798 MW	

Table 1.1-1 presents a listing of all the CECo generating facilities as of summer of 1978 showing the station and unit name, year of installation, and net generating capability. 2 Footnotes in Table 1.1-1 give the key to unit type and show which CECo units are cooperatively owned. At the present time, the only units in which CECo participates jointly are the Quad Cities Nuclear Units shared with Iowa-Illinois Gas and Electric Company (3/4 and 1/4, respectively).

CECo's program for conservation in the consumption of electrical energy has remained basically unchanged for the last 5 years. New ideas and sales promotion techniques, however, have been employed to increase the effectiveness of customer energy conservation. Radio and TV commercials, newspaper releases on energy conservation, and newspaper ads in both major Chicago metropolitan newspapers and local and regional papers are all directed at helping

all classes of customers in the "wise" and "efficient" use of electricity (see Figures 1.1-1 through 1.1-9). CECo's booklet "101 Ways to Conserve Electricity at Home" succinctly provides customers with suggestions on energy savings for oil and gas as well as electricity. Proper selection of new appliances (air conditioners with high EER's, well-insulated ovens, heat pumps, and non-frost-free refrigerator-freezers) and the proper maintenance of both new and existing appliances are items mentioned that help reduce electricity costs and conserve energy. Furthermore, a program has been recently developed to ensure that CECo's 80,000 largest commercial and industrial customers are contacted by a marketing field person within a 3-year period. The customers are surveyed to determine their energy needs, energy substitution considerations, and expansion or relocation plans. The aim of the program is to inform these customers of "wise" energy utilization and future energy availability.

Innovative engineering planning, design, and operation of new and present system facilities are other ways being developed to conserve energy resources. Examples of these include:

a. studying the feasibility of compressed air, underground pumped hydro, and electrochemical cells to conserve scarce energy resources (petroleum and natural gas);

b. peak load management with thermal energy devices to make better use of off-peak energy as well as automatic meter reading systems with time of day meter reading capacity to permit implementation of load management methods;

c. research into solar energy feasibility and the electric car;

d. augmentation reservoirs near large nuclear and fossil plants to avoid summer limitations due to cooling water makeup problems;

e. economy interchanges with neighboring utilities to conserve scarce fuels; and

f. transmission and distribution engineering innovation and improvements to reduce energy demand and losses.

During the past several years CECo, like other electric utilities, has found it necessary to increase its rates. Although this increase has undoubtedly had the effect of

causing many customers to reduce consumption, CECo has no way of measuring this reduction.

In addition to the general increase in charges, CECo has been significantly restructuring its rates to more closely reflect the changing costs of providing electric service to different customers at different times. Because the peak demand for CECo's service occurs on hot summer days, summer demand charges have been increased substantially more than the demand charges applicable in other months. In addition, electric space-heating customers pay higher charges for service in the summer months than in the non-summer months. Also, because production costs are higher during the heavy-load daytime and early evening hours of working days than during nighttime and early morning hours of such days or on weekends, CECo has a mandatory time-of-day rate that is applicable to about 700 of its largest customers, which account for nearly a third of CECo's annual kilowatt-hour sales. Under the rate, kilowatt-hours used during on-peak hours cost substantially more than kilowatt-hours used during off-peak hours. CECo has also proposed a time-of-day rate experiment with residential customers.

While CECo is not certain of the extent to which such rate restructuring will result in energy conservation, the new rates offer better incentives for customers to cut back on consumption when electricity is most costly to produce and use it instead when it is least expensive to produce. If customers shift load from peak to off-peak times, it will result in a long-run capacity saving and probably an immediate oil saving since during peak hours CECo is often operating combustion turbines or steam cycling units fired by expensive and scarce oil. Even then, however, oil is responsible for only a small percentage of the total generation. During off-peak hours, oil is most often not used at all. Any consumption shifted from peak to off-peak hours, therefore, reduces oil burn, which is replaced by the use of coal or nuclear fuel during the off-peak hours.

1.1.1 Load Characteristics

1.1.1.1 Load Analysis

Table 1.1-2 shows the actual annual peak load demand and kilowatt-hour consumption for the CECo system from 1962 to 1978, and the estimated annual peak load demand and kilowatt-hour consumption from 1979 until 2000 are shown in 2
Table 1.1-3. Since the Carroll County Station units will be in service for 30 to 40 years, it is difficult to project total CECo system demand over their entire lifetime. The present CECo load demands are currently projected through the year 2000.

The load duration curve for the year 1978 is shown in Figure 1.1-10, and the supporting data are listed in Table 1.1-4. Table 1.1-5 gives a monthly summary for 1978 of various load parameters. The load duration curves for the years 1981, 1983, 1987, and 1988 will closely resemble the curve on Figure 1.1-10 since the annual load factors will be nearly the same. With the units at the Carroll County Station in service, the base load capacity will be about 69 percent of the total expected system capacity in the 1991-1996 time period. This amount of base load capacity is in accord with industry-wide studies of economical generation mixes. It also agrees with CECo's generalized studies that indicate that base load generation is the most economical form of generation when operated over 3,000 hours per year.

Figure 1.1-11 is the daily load duration curve for Friday, September 8, 1978, which is the peak day for CECo in 1978. The estimated load for 1978 was 14,450 MW and the actual recorded peak was 13,720 MW. Table 1.1-6 shows the data for the peak load day. Firm power sales on that day were 57 MW and firm purchases totaled 500 MW. Due to a large amount of generation out of service and summer limitations, CECo was forced to import an additional 1,225 MW to meet peak demand requirements. 2

1.1.1.2 Demand Characteristics

The installation of new generating units requires long lead times. Consequently, forecasts of peak demand for electricity as far as 10 years into the future are made to offer a guide to the amount of new capacity required, and the output forecasts help determine the type of new capacity. Table 1.1-7 lists actual peak demand and output for the years 1960 through 1978 and projections of peak demand and output through the year 2000.

Commonwealth Edison Company (CECo) establishes peak demand projections by using a multiple-model approach refined by a multidisciplinary review committee. The Company's load forecasting staff is responsible for analyzing demands, identifying factors that can affect peak demands, and developing mathematical forecasting models. The load forecasting staff has used two types of models: econometric models and engineering models.

An econometric model relies on historical data to explain the extent to which selected explanatory variables explain past variations of the dependent variable, i.e., peak load. The explanatory variables are factors that might affect peak loads, such as the level of business activity, income, price

902086

of electricity, weather, etc. In order to forecast demand, the values of the explanatory variables must be projected and the quality of those projections determines to a great extent the ability of any econometric model to predict the future. Consequently, the selection of explanatory variables and their projected values introduce a certain degree of judgment.

The load forecasting staff is also investigating the use of "engineering" or "end use" models to determine the effect certain factors might have on demand. Items such as time-of-use pricing, appliance efficiency standards, long range conservation effects, and substitution of one energy source for another are identified as policy issues and are best addressed outside the econometric process.

CECo's Load Estimates Committee (LEC) is responsible for forecasting peak demands. The LEC reviews the methods and assumptions used to produce the technical forecasts and directs the work of the load forecasting staff. The Committee has 13 senior management members representing several areas in the Company. Each member of the Committee, because of his background within CECo, brings a unique viewpoint and judgmental approach into the decision-making process. The 2
Committee's forecasts, then, represent a balance of attitudes and judgments.

The LEC and the load forecasting staff maintain regular contact with consultants outside CECo. These consultants ensure an unbiased review of the models and assumptions going into them and recommend improvements.

Based on the Committee's judgment and knowledge of activity in CECo's service territory, model results, and opinions of others, the LEC determined the most likely 1978-1988 average annual compound peak load growth rate to be 4.5 percent. The LEC also determined the low and high peak load forecasts to be 4.0 percent and 5.0 percent, respectively. These forecasts provide lower and upper bounds for capacity planning purposes.

Summary of Technical Work

Econometric Models - Three econometric peak load forecasting models were used to provide input during the 1978 forecasting process. An example model is illustrated below. If it were believed that base load, the dependent variable, was influenced by income, number of customers, and electricity price, then a simple econometric model could take the following form:

$$\text{Base Load} = a_1\overset{X_1}{(\text{Income})} + a_2\overset{X_2}{(\text{Customers})} + a_3\overset{X_3}{(\text{Price})}$$

a's = coefficients

X's = explanatory variables

The first step would be to perform a least squares multiple regression, by using as input the historical values of base load and the explanatory variables, the "X's". This regression process would then estimate numerical values for the coefficients, or "a's". In order to forecast with the model, now that a_1, a_2, and a_3 have been estimated, future values for each of the "X's" would be predicted and multiplied by the appropriate coefficient. The sum of these products would yield a forecast. Although the models used by the load forecasting staff are substantially more complex than the above example, the basic theory and practice remain the same.

CECo's three econometric models are briefly described below. 2

1. Model I: Model I consists of two equations that are used to estimate annual system peaks. One equation estimates the base load and the other estimates the weather-sensitive load. Ordinary least squares regression is the method of estimation. The sum of the base load and weather sensitive load estimates yields the peak load forecast. The base load equation considers two variables to explain and predict base load growth:

   (1) FRB Index of Industrial Production, and

   (2) a measure of time which reflects the growth trend of CECo's service area.

   The weather sensitive load equation considers 10 weather variables and a mathematical function which attempts to reflect the expectation that future weather-sensitive loads will grow at a declining rate due to air conditioning saturation.

2. Model III: This model also has two equations, one for the base load and the other for the peak load. The estimated base load is included as a jointly dependent variable in the peak load equation. Two stage least squares is used as the method of estimation. The base load equation

902088

considers eight variables: (1) price of electricity, (2-5) price lagged 1, 2, 3, and 4 years, (6) Illinois Gross State Product, (7) customer index, and (8) a dummy variable. The peak load equation considers six variables: (1) estimated base load, (2) price of electricity, (3) air conditioning saturation, and (4-6) weather variables.

3. Model IV: This model also has two equations, one for the base load and the other for the weather-sensitive load. The combination of the two yields the peak load forecast. Seemingly unrelated regression is used as the method of estimation. The base load equation considers nine variables: (1) price of electricity, (2-5) price lagged 1, 2, 3, and 4 years, (6) Illinois Gross State Product, (7) customer index, (8) price of natural gas, and (9) a dummy variable. The weather-sensitive load equation considers four variables: (1) residential air conditioning saturation, (2-3) weather variables, and (4) a dummy variable.

The models and definitions of the independent variables are described in further detail in Section 1.1.1.2.1. 2

Determination of Dependent Variables - The reconstructed peak load adjusts the actual peak load to a basis consistent with other years by reflecting estimated load reductions caused by industrial vacations, voltage reductions, curtailment of electric furnace interruptible service, etc.

Base load is defined as that load observed when non-weather-sensitive load is at a normal level and total heating and cooling loads are at their practical minimum. A line is fit through the ten lowest spring and the ten lowest fall weekday, nonholiday daily peak loads using simple linear regression. Base load values for peak days during the summer are then interpolated from this line.

Because the 10 base load values during each spring and fall do not necessarily increase over time, base load values, in the future, will be determined from a line fit between the average of the 10 spring and the average of the 10 fall lowest weekday, nonholiday daily peak loads.

Weather-sensitive load, then, is the reconstructed peak load minus the base load.

Weather Adjustment - In addition, the 1978 reconstructed peak load was adjusted upward to reflect the cooler-than-normal weather experienced during the summer of 1978. This weather adjustment is intended to reflect average peak-making weather conditions. The weather adjusted, reconstructed peak load is used only as a reference point when estimating 1979-1988 peak loads.

Several weather adjustment techniques were used to develop the 1978 weather adjusted, reconstructed peak load:

1. The econometric models are capable of weather adjusting because they include weather variables and because assumptions can be made regarding expected values for these weather variables.

2. The relationship between weather-sensitive load and certain weather variables believed important for peak-making conditions was modeled.

3. A weather index was developed and used to adjust the estimated weather-sensitive load to average peak-making weather conditions. 2

Pı jections of Explanatory Variables - Future values of the explanatory variables must be projected in order to arrive at a forecast. The variables and their respective 10-year average annual growth rate assumptions are noted below:

	GROWTH RATE
1. Illinois Gross State Product	2.27%
2. FRB Index of Industrial Production	3.14%
3. Customer Index:	1.50%
Residential	1.48%
Commercial & Industrial Inside Chicago	-1.13%
Commercial & Industrial Outside Chicago	2.50%

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4. Real Price of Electricity:

Marginal	-2.70% in 1979 1.00% thereafter
Average	3.20% in 1979 1.00% thereafter

5. Real Price of Natural Gas — 4.80%

6. Air Conditioning Saturation:

Model III	3.47% in 1979 and gradually declining to 1.15% in 1988
Model IV	4.94% in 1979 and gradually declining to 2.66% in 1988

7. Weather — Average Peak Making Weather

Documentation of the independent variable projections is provided in Section 1.1.1.2.6.

End Use Considerations - The load forecasting staff is also investigating the use of "engineering" or "end use" models to determine the effect that specific uses of electricity might have on demand. Such models complement an econometric model that is incapable of determining or isolating the impact of a particular appliance on demand. 2

In addition, there are several policy issues, not explicitly considered by engineering or econometric models, which could impact on future demands for electricity. Some of these issues, such as customer-owned demand control devices, fuel switching, cogeneration, etc., have been examined to assess possible influence on future peak loads.

These end use considerations are outlined in greater detail in Sections 1.1.1.2.1 through 1.1.1.2.5.

Development of High and Low Projections - The LEC is responsible for establishing the low and high 1978-1988 peak load growth rates in conjunction with the most likely forecast. The low and high forecasts provide the lower and upper bounds needed for capacity planning.

Four methodologies were considered in developing the low and high forecasts:

1. Low and high forecasts can be developed from the accuracy of past load estimates. If it were assumed (1) that CECo's load forecasting

error follows a normal distribution and (2) that the approved most likely 1979-1988 estimates are as "good" as past estimates, then there is a 95 percent probability that the load for each year for the next 10 years would be within plus or minus 2 standard deviations of the expected values. The forecast ± 2 standard deviations, then, would represent the lower and upper bounds.

2. The low forecast could be based on the model providing the lowest forecast and the high forecast could be based on the model showing the highest forecast.

3. A 95 percent confidence interval can be developed around the most likely 1979-1988 estimates using the forecast error from an econometric model.

4. Lower and upper bounds can be determined by either adding one year's growth to, or subtracting it from the 1979-1988 forecast.

Although all four methods were investigated thoroughly, the fourth methodology was selected and received strong support from the results of method three. 2

Development of the 1979-1988 Forecast

During its deliberations, the LEC reviewed and discussed model results, the underlying assumptions of future economic conditions, the economic outlook for CECo's service territory, outside economic and industry forecasts, and growth rates of recent periods.

The models provided the following 10-year forecasts:

Model I	5.0%
Model III	4.9%
Model IV	3.8%

Based on all factors presented above, the LEC approved the following 1978-1988 average annual compound peak load growth rates:

High Growth	5.0%
Most Likely Growth	4.5%
Low Growth	4.0%

1.1.1.2.1 Load Forecasting Methodology

Because of the long lead time required to install new generating units, forecasts of peak demand as far as 10 years into the future must be made. The demand forecasts offer a guide to the amount of new capacity required.

There are some readily apparent factors that can affect peak electrical loads, such as the level of business activity and weather. These two factors, however, are only a small part of a complex structure of economic, social, and psychological interactions affecting the demand for electricity. Because of this complexity, the forecasting of electrical peak demands requires a high degree of judgment and involves unavoidable error. CECo attempts to minimize the forecasting error by using a multiple-model approach refined by a multidisciplinary review committee.

There are many forecasting techniques available, many of which use statistical models that attempt to correlate the effects of many variables into a systematic series of projections. Regardless of the techniques employed, whether simple straight-line analyses or complex econometric models, there is at least one weakness common to all: they rely on historical data. They cannot take into account new factors. The best means of identifying new factors is still through informed judgment. Because of this deficiency, even the best model cannot always predict turning points or other aberrations in long-run trends. 2

The responsibility for forecasting annual peak demands is assigned to CECo's Load Estimates Committee. The Committee has 13 senior management members representing the following areas of CECo: Rates, Engineering, Division Operations, Marketing, System Planning, Power Supply, Fuel and Budgets, Statistical Research, and Financial. Each member of the Committee, because of his background within CECo, brings a different viewpoint and judgmental approach into the decision-making process. The Committee's forecasts, because of the influences of its various members, represent a balance of attitudes and judgments. The Load Estimates Committee meets at least twice a year, after the establishment of the year's summer and winter peak demands. Meetings are held more frequently as conditions warrant.

The forecasts, however, are not based upon judgment alone. Within CECo's Statistical Research Department is a group of analysts with the necessary economic, mathematical, computer, and other technical skills to analyze demands and develop mathematical models that can aid the Load

Estimates Committee. The techniques employed by this group have varied over recent years to accommodate changing conditions.

Up until the mid-1960's the lead time required to build new generating units was 5 years or less. In addition, during the period up to 1973, load growth followed a regular pattern with electrical demands doubling approximately every 10 years. Trend lines fitted to various periods of growth in demand could have provided adequate guidance for the Load Estimates Committee to make its decisions. During the Committee's deliberations in the mid-1960's, there was a growing awareness that changes were occurring. For example, since 1964, the summer peak demand has also been the peak demand for the year. As a result, different models were developed and analyzed in an attempt to isolate these changes and improve the forecasting guides. Such models have since provided one of the bases for CECo's official demand estimates. One of these models, referred to as Model I, was developed in 1966 and has been undergoing considerable modification as the knowledge of its operation and reliability has progressed. A Model II was developed; however, it had some serious shortcomings, the most severe being the model's inability to predict the historical growth rate in peak demand when actual historical values are inserted for all the explanatory variables. It was, therefore, decided that this single-equation model was unable to derive accurate peak demand forecasts since it was incapable of responding to independent forces affecting the base and weather-sensitive demands. Consequently, the Load Estimates Committee no longer considers Model II. The Statistical Research Department has also considered other, more elaborate, econometric models. Two such models, referred to as Model III and Model IV, attempt particularly to explain some of the changes in demand patterns that have occurred since the Arab oil embargo in late 1973. 2

The Load Estimates Committee is continually reviewing the latest forecasting techniques and testing the models in many ways. Traditional statistical measures to determine correlation, standard error of estimate, goodness of fit, etc. are used. As part of the constant review of forecasting methodologies, tests of models using most recently observed data are also conducted to determine how well each model "predicts." However, the output of any model is only as good as the input data and the user's understanding of the workings of the model. In addition, the models are constantly analyzed by altering the method of estimation, examining and redefining explanatory variables, and testing experimental variables. CECo is proceeding cautiously and

systematically to develop new models and to improve the input and test functioning of existing models.

1.1.1.2.2 Model I

Model I is a two-equation econometric model used to estimate annual system peaks. One equation estimates base load at the time of system peak and the other estimates weather sensitive load at the time of system peak. Each of the two components is analyzed and forecast separately. They are then summed to arrive at the projected summer peak demand. The estimating equations were developed using the statistical method of multiple linear regression analysis.

In its present configuration, the base load equation of Model I considers two variables to explain and predict base load growth. They are: (1) a measure of industrial activity (Federal Reserve Board Index of Industrial Production), and (2) a measure of time which reflects the growth trend of our service area.

The weather-sensitive equation considers 10 weather variables and a mathematical function which attempts to reflect the expectation that future growth of weather-sensitive load will be at a declining rate. See Table 1.1-8 for a description of Model I. 2

The 10 weather variables are intended to explain the impact of weather conditions on weather-sensitive load. The variables were selected to reflect not only the conditions on the peak day, but also the heat build-up effect of prior hot days.

The mathematical function which attempts to reflect the declining future growth rate of weather-sensitive load is known as the Gompertz function. Use of this function allows weather-sensitive growth to take the form of the traditional "s" shaped growth curve. The use of the Gompertz function is an implicit recognition of air conditioning saturation. The time and level of "flattening out" is determined by the numerical value of the Gompertz coefficient.

Model I coefficients are determined by regression on a data base consisting of the highest and second highest summer loads during each year from 1959 through 1978 (see Table 1.1-9).

For Model I estimates, peak-making weather is defined as the average weather that existed over the past 20 years at the time the summer peak demand occurred. For the 10 weather variables used in the model, a 20-year average peak-making value was calculated for each variable (see

Table 1.1-10). Averages rather than maxima are used in order to represent the most probable case rather than the highest possible case. Base load forecasts are then prepared by estimating the yearly values for the FRB Index at the expected time of system peak for each year and computing the resulting base demands for each year. The estimated summer peak demand is obtained by adding the estimated base load for a year to the weather component for that year. The estimated summer peak demands and the underlying variable assumptions are then presented to the Load Estimates Committee for review.

1.1.1.2.3 Model III

Model III is an econometric peak load model developed in 1976 and uses two stage least squares estimation. Model III consists of two equations, one to explain the base load and the other to explain the total system peak load. The base load is included as a jointly dependent variable in the total peak load equation. The projected weather-sensitive load is then the difference between the projected peak load and projected base load. See Table 1.1-11 for a description 2
of Model III. The explanatory variables in Model III are listed below and defined in Table 1.1-12.

BASE LOAD EQUATION	TOTAL PEAK LOAD EQUATION
1a. Real price index of electricity to all CECo customers (Marginal Price)	1b. Estimated base load
2a. Price lagged 1 year	2b. Real price index of electricity to all CECo customers (Marginal Price)
3a. Price lagged 2 years	3b. Air conditioning saturation
4a. Price lagged 3 years	4b. Three weather variables representing temperature, humidity, and summer heat build-up
5a. Price lagged 4 years	
6a. Illinois Gross State Product	
7a. CECo customer index	
8a. Dummy variable	

The data base for Model III consists of observations for all variables for the peak day of June, July, and August of each year beginning in 1959 (see Table 1.1-13).

1.1.1.2.4 Model IV

Model IV is the most recent attempt to advance CECo's ability to forecast. The model has the following noteworthy characteristics (see Table 1.1-14 for a description of Model IV):

a. The model consists of two equations, one for the base load and the other for the weather-sensitive load. The combination of the two yields the peak load forecast.

b. The model obtains estimates of the parameters using a method called Seemingly Unrelated Regression (SUR). This method was not used on other forecasting models.

c. The model includes some new or redefined explanatory variables. The new variables are the real price index of competing fuels (natural gas) and a variable that considers short term heat build-up. The redefined variables are the real price index of electricity and the residential air conditioning saturation index. 2

The explanatory variables in Model IV are as follows:

BASE LOAD EQUATION	WEATHER-SENSITIVE LOAD EQUATION
1a. Real price index of electricity to all CECo customers (Average Price)	1b. Residential air conditioning saturation
2a. Price lagged 1 year	2b. Two weather variables representing temperature, humidity, and summer heat build-up
3a. Price lagged 2 years	3b. Dummy variable to account for unusual weather-sensitive load observations 2 in 1963 and 1964

4a. Price lagged 3 years

5a. Price lagged 4 years

6a. Illinois Gross State Product (Income)

7a. CECo customer index (number of customers)

8a. Real price index of natural gas in Illinois (price of competing fuels)

9a. Dummy variable to account for low base load observations in 1974 and 1975 2

Since only total system loads can be observed, the historical values for the base load and weather-sensitive load components must be estimated. Consequently, unobserved measurement error could result in each equation. That is, if the base load is overstated, the weather-sensitive load would be understated by the same amount since the sum of the two loads must equal the total reconstructed peak load. Although an error in estimating the base and weather-sensitive loads would be equal and offsetting, the values of the historical dependent variables could still be incorrect. The method of estimation referred to as SUR reduces the impact of possible measurement errors in the two equations.

The data base for Model IV consists of observations for all variables for the peak day of June, July, and August of each year beginning in 1959 (see Table 1.1-16).

1.1.1.2.5 Engineering Models and Policy Issues

Econometric models have been the primary model input to peak demand forecasting. The ability of any econometric model to predict the future is dependent on the quality of the projections on the explanatory variables. In some cases, however, insufficient data on a variable would prevent its inclusion in a model.

Since econometric models rely on history to estimate their coefficients, changing relationships which have no historical precedent cannot be predicted by econometric models. For example, although we believe there is some consumer response to increasing electricity prices, we do not know the extent of consumer response to time-of-use pricing. The effect of legislation and governmental policies, the impact of more efficient use of energy, and mandatory conservation are other recent utility concerns where extensive historical data are unavailable. Such items are identified as policy issues and are best addressed outside the econometric process. Policy issues that might affect future peak loads are described in following pages.

CECo is currently investigating and developing "engineering" or "end use" models to determine the effect of specific types of energy-using equipment on demand. One engineering model examines the impact of residential air conditioning on the weather-sensitive load. The fundamental relationship in this model is that, at each point in time considered, 2

$$MW_{AC-R} = \frac{(C_R)\ (S_{AC})\ (SIZE)\ (CF)}{(EER)}$$

where:

MW_{AC-R} = load attributable to residential air conditioners

C_R = number of residential customers

S_{AC} = residential air conditioning saturation

SIZE = representative unit size, BTU/hour

CF = coincidence factor

EER = energy efficiency ratio, BTU/hour/watt

It is impractical to develop engineering models for all present uses of electricity, and it is difficult to expand engineering model results to the total peak load. However, their sensitivity to the factors affecting use of a particular appliance complements the use of econometric models, particularly in the case of factors which are expected to deviate from historical trends.

Policy issues that might affect future peak loads are listed below:

Time-of-Use Pricing

Although widely studied, there are no conclusions as to the specific impact of time-of-use pricing. Of principal concern is the difference between price induced loss of consumption and price induced switching of consumption. All of the literature suggests a dampening of peak demands, although the extent is not clear. This issue will be watched carefully as more data and conclusions are available, both locally and nationally.

Customer-Owned Demand Control Devices

A number of these devices, which act to limit a customer's peak demand, have been installed in our service area, mainly on the premises of large commercial and industrial customers. To the extent that higher electricity prices encourage the installation of these devices, their impact might be implicitly captured by the price variables used in the forecasting models. The load forecasting staff has estimated that the effect of these devices might have reduced the 1978 peak by as much as 75 MW. The load forecasting staff is currently working with Marketing Services to obtain a more accurate picture of the present and future impact of these devices. 2

Fuel Switching

The process energy requirements of the industrial sector are considered most likely to switch from fossil fuels to electricity. Energy prices and availability would influence the rate and extent of such switching. While it is felt that availability of natural gas will not be a major near term concern of customers in the Commonwealth Edison service area, changes in the relative prices of natural gas and electricity will encourage some degree of switching.

Estimates were made of potential fuel switching by disaggregating our industrial customers according to SIC code, and then converting estimated gas usage into KWH for each industry. It was assumed that industrial gas usage in the absence of switching would grow at 3 percent per year. A survey done in 1976 by Stone and Webster, management consultants for EEI, gives the proportion of firms within each SIC code indicating that they plan to switch from gas to other fuels within 2-5 years and within 5-10 years. These proportions were used to estimate the maximum additional KWH

from fuel switching. For the high, medium, and low estimates it was assumed that switching firms would shift 50, 25, and 5 percent of their gas usage to electricity, respectively. Load factors appropriate to each SIC code were applied to the estimated KWH to obtain high, medium, and low MW estimates.

Using this analysis, high, medium, and low increments to demand as a result of fuel switching have been estimated for 1986 by the load forecasting staff. They are as follows:

High	1,100 MW
Medium	560 MW
Low	110 MW

Cogeneration

Based on earlier work of CECo's Cogeneration Task Force, impact on peak load by 1985 could be up to 50 MW. This task force is currently updating its earlier study which is expected to provide a higher estimate of the impact on peak load. 2

Appliance Efficiency Standards

Mandatory appliance efficiency standards which would impact on all appliances manufactured after 1980 could reduce 1988 peak load by as much as 735 MW. The bulk of this reduction, 580 MW, would come from improved EER's for air conditioners.

Concern has been expressed that the EER definition being considered by the Department of Energy might provide substantially greater EER improvement at partial load conditions than at full load conditions. Such a definition would have adverse effects on the electric utility industry.

Wind and Solar Power

Within the 10-year forecast horizon, wind and solar power are not expected to have measurable impact on peak loads. Although solar power could have measurable values during winter peak conditions, the most likely applications, space and water heating, are not likely to influence summer peak conditions.

Electric Vehicles

Considering the time which would be required to move practical electric vehicle technology from laboratory to commercial status, design and development time, and slow early year market acceptance, the electric vehicle could at best be expected to be in the very early stages of market penetration by 1988. In any case, the great majority of charging load would not be expected during the normal summer peak hours.

In addition to the issues summarized above, two additional issues have been identified and will be examined during the next year. These additional issues are: (1) industrial air conditioning and (2) increased loads from environmental compliance devices.

1.1.1.2.6 Explanatory Variable Projections

In order to forecast the peak demand for electricity with an econometric model, future values of the explanatory variables used in that model must be determined. The quality of these future values determines to a great extent the ability of any econometric model to predict the future. 2
The more complex the model, the more projections of explanatory variables need to be made. Incorrect projections of income, number of customers, prices, or other variables might result in a poor forecast of peak load even if sophisticated techniques for employing these projections are used in the methodology. Although some of the assumptions regarding future values may be made mathematically, based on historical trends, all require some judgment. The Load Estimates Committee is responsible for arriving at the final set of assumptions used in each model. The importance of these judgments in affecting predictions is why model outputs are not adopted directly in determining CECo's official 1979-1988 forecasts. Table 1.1-16 is a summary sheet of the assumptions used on the explanatory variables.

1.1.1.2.7 Other Forecast Guides

The following are two forecast guides employed by CECo:

A. Growth Matrix

The "Growth Matrix" (see Table 1.1-18) provides a check as to the reasonableness of a 10-year peak load forecast based on various combinations of base load and weather-sensitive load 10-year forecasts. For example, if one were to assume 10-year growth rates of 3.0 percent for base load and 7.0 percent for weather-sensitive

load, then the 10-year growth rate for peak load is expected to be 4.8 percent.

B. Growth Projections Made By Others

The Load Estimates Committee also considers growth rates and projections made by others. Various comparative growth rates and forecasts made by associations and trade groups are presented for comparison in Table 1.1-19. CECo's average annual peak load forecast of 4.5 percent appears reasonable when compared with those of other associations.

1.1.1.2.8 Historical Accuracy of Peak Load Forecasts

A comparison of past CECo demand projections and the actual loads experienced are presented in Table 1.1-20. The estimates, expressed as percentages of the actual peak loads, are presented in Table 1.1-21. Furthermore, estimates expressed as percentages of the "reconstructed" peak loads are presented in Table 1.1-22. The "reconstructed" peak load (calculated for the years 1959-1978 in Table 1.1-23) adjusts the actual peak load to its maximum potential by reflecting estimated load reductions caused by 2
industrial vacations, voltage reductions, electric furnace interruptible service, etc.

1.1.1.2.9 Development of the 1979-1988 Peak Load Estimates

During its deliberations, the Load Estimates Committee reviewed and discussed model results and the underlying assumptions of future economic conditions. This involved such matters as: business activity, housing starts, expected number of customers, relative vitality of the service area, prices and availability of alternative energy sources, evolving technologies, appliance saturations, and regulatory considerations. The results from the forecasting methodologies and the Committee's knowledge of activity in CECo's service area indicated that consumer patterns may be changing such that electric demand will increase at a lower rate than it has in the past 10 years. Several specific points were made during the deliberations:

1. The November 1973 "energy crisis" has to date been followed by peak load growth rates that were less than those experienced before the embargo.

2. There is a possibility that recent peak load performance reflects a one-time adjustment to new conditions, after which growth rates will return to more traditional patterns.

3. Estimates of the extent to which the policy issues (see Section 1.1.1.2.5) will affect electrical loads are preliminary, pending further investigation.

4. Of the policy issues considered by the Committee, only fuel switching could be expected to exert a strong upward pressure on future loads. The remaining major policy issues (appliance efficiencies, time-of-day rates, cogeneration, and customer-owned demand control devices) suggest a retardation of future growth rates.

5. There is some evidence to suggest that the impact of electricity price effects may be greater than originally thought. Although the overall rate of inflation is expected to remain high, real electricity prices are expected to increase over the forecast horizon. Both of these factors will probably tend to make consumers increasingly aware of their energy consumption habits.

In light of model indications, opinions of others, and the best judgment of the Committee, it was determined that there was a greater probability of achieving a 10-year growth rate of 4.5 percent than the previous official forecast rate of 5.1 percent. All members of the Committee concurred, and a 10-year forecast showing an average annual compound growth rate of 4.5 percent was adopted.

On February 6, 1979 the Load Estimates Committee reviewed and approved the 1979-1988 low, most likely, and high peak load estimates listed below. The Committee also reviewed estimates from the Company's models as well as the explanatory variable assumptions used in them, the economic outlook for CECo's service territory, outside economic and industry forecasts, and growth rates of recent periods. Based on all these factors, the Committee approved the following 1978-1988 average annual compound peak load growth rates:

High Growth	5.0 %
Most Likely Growth	4.5 %
Low Growth	4.0 %

The official peak load estimates are presented in Table 1.1-24.

1.1.1.3 Power Exchanges

Table 1.1-25 shows the net power exchanges at the time of the past annual peak loads from 1962 to 1978. The expected net power exchanges for 1979 are also shown. All purchases after 1979 solely reflect CECo's Ludington purchases. 2

1.1.2 System Capacity

The power planning programs are predicated on the forecasts by the Load Estimates Committee. As discussed earlier, three forecasts are made based upon an official estimate that is bracketed by a high load and a low load estimate.

Generation capacity additions are proposed for each of the three load growth plans. The intent of the capacity additions is to provide capacity sufficient to meet system demand, total kilowatt-hour production requirements, and a required reserve margin to cover generation outages. CECo uses a 14 percent minimum reserve margin for generating facilities. The reserve margin consists of CECo-owned generating capacity less firm sales and summer limitations plus firm purchases, diversity exchange, and the Ludington purchase less the expected yearly peak load.

Generation facilities are added to the CECo system by choosing the type of generating facility that will not only provide kilowatt capacity, but when added to the existing generating system, will most economically satisfy the load. A computer program called PROMOD, which simulates the CECo generation schedule and economically loads the units according to their fuel cost, is used by CECo to make choices of potential generation additions. The program not only determines how the unit will operate, but also how it will affect the operation of all the other units. The PROMOD system can forecast 10 years or more into the future to measure the impact of a generating unit over a broad time horizon. As additional units are added in succeeding years to satisfy kilowatt demand and kilowatt-hour consumption, the resulting mix of units will be loaded to satisfy requirements according to the economic operation of the units.

Table 1.1-26 lists the new generating units planned between 1978 and 1991. The 550 MW units shown are cyclical coal units whereas the larger units are nuclear units. Table 1.1-27 lists the retirements schedule between 1978 and 1992. 2

The projected unit capabilities and capacity factors for the units listed in Table 1.1-1 are shown in Table 1.1-28. 2

These capacity factors through 1991 are predicated on CECo's load growing according to CECo's official load growth estimates and on planned new generating units being added according to the tabulation in Table 1.1-29. The capacity factors for these units will change if either the generation addition pattern (see Table 1.1-29) or the peak load growth pattern is changed.

1.1.3 Reserve Margins - Generating System Reliability

Generating system reliability for an electric utility is a function of many parameters among which is system reserve margin, number, size and forced outage rate of each type of generating unit, system load profile, uncertainty of load forecast, strength of interconnections to other systems, and planned generating unit maintenance. Utilities attempt to directly control the level of system reliability by installing additional generating capacity to achieve a target reserve margin. This reserve margin serves to provide, in part, the necessary added generating capability to prevent interruption of customer load when generating units fail and are forced out of service. 2

1.1.3.1 Percent Reserve Margin

Expressing reserve margin as a percent of system annual peak load is a convenient way of stating reserve margin levels. Commonwealth Edison plans new generating capacity to result in a 14 percent target reserve margin level. Loss of Load Probability (LOLP) studies indicate that 14 percent planned reserve, in conjunction with expected help from interconnections, will result in an LOLP of about 1 day in 10 years. Furthermore, Edison has planned for this level over a period of many years and the result has been a high degree of generating system reliability. Although this 14 percent reserve margin is somewhat lower than the margins used by many companies, we believe it adequate because of Commonwealth Edison's strong interconnections.

1.1.3.2 Interconnections

The role of interconnections is extremely critical to generating system reliability. They allow reserves of one utility to be shared with those of neighboring utilities, raising the overall reliability level of both utilities. The net result is that each utility benefits by needing lower reserve levels and thus less generating capacity to achieve a desired degree of reliability. In fact, LOLP studies have shown that Edison would require reserve margins of about 30 percent were it not for interconnections.

Table 1.1-30 summarizes load and capacity projections for peak periods from 1979 through 1992, and shows the estimated reserve margin for each year.

Reduced load estimates following the Arab oil embargo and the subsequent recession have had a significant effect on the relationship between planned capacity and estimates of future loads and capacity requirements. Therefore, although present estimates for completion of the two Carroll County Units are for the fall of 1990 and 1991, these units could be delayed. 2

1.1.4 External Supporting Studies

Although CECo is not a member of a power pool, as a member of the Mid-America Interpool Network (MAIN) it attempts to maintain its share of MAIN reserves.

Because reliability is a region-wide concern and not just an individual utility concern, Commonwealth Edison relies heavily on the work done by the MAIN Guide #6 Working Group in which it is an active participant.

MAIN Guide #6, "Procedure of Generation Reserve Requirements," establishes a procedure for determining minimum generation reserve requirements for MAIN as an aid in planning future generation. The MAIN Executive Committee in November, 1978 revised MAIN Guide #6 adopting the LOLP method for the determination of minimum generation reserve requirements for MAIN and a criterion of a LOLP of 1 day in 10 years as an aid in planning future generation. Prior to that, MAIN used the Probability of Positive Margin method, which is a less sophisticated tool than LOLP.

TABLE 1.1-1

EXISTING COMMONWEALTH EDISON COMPANY GENERATING UNITS

AS OF SUMMER OF 1978

STATION - UNIT	TYPE OF UNIT[a]	YEAR OF INSTALLATION	NET CAPABILITY (MW) WINTER	SUMMER
Bloom T.S.S. 33, 34	P	1971	150	121
Calumet 31-34	P	1969-70	290	229
Collins 3	O	1977	500	500
" 2	O	1977	510	510
" 1	O	1978	515	515
Crawford 7	C	1958	222	219
" 8	C	1961	326	319
" 31-33	P	1968	207	161
Dresden 1	N	1960	207	197
" 2	N	1970	794	772
" 3	N	1971	794	773
Electric Junction 31-34	P	1970-71	296	238
Fisk 19	C	1959	341	336
" 20	D	1966	11	11
" 31-34	P	1968	312	238
Joliet 6	C	1959	340	330
" 7	C	1965	537	533
" 8	C	1966	537	533
" 9	D	1967	11	11
" 31,32	P	1969	154	123
Kincaid 1	C	1967	606	606
" 2	C	1968	606	606
Lombard 31-33	P	1969	139	111
Powerton 5	C	1972	850	850
" 6	C	1975	850	850
Quad Cities[b] 1	N	1972	591	576
" " 2	N	1972	592	577
Ridgeland 1	O	1951	163	157
" 2	O	1950	158	152
" 3	O	1953	143	137
" 4	O	1955	142	136
Sabrooke 31-34	P	1969-70	153	123
State Line 2	C	1938	140	140
" " 3	C	1955	190	190
" " 4	C	1962	318	318
Waukegan 6	C	1952	88	88
" 7	C	1958	328	328
" 8	C	1962	358	358
" 31, 32	P	1966	156	119
Will County 1	C	1955	144	139
" " 2	C	1955	167	161
" " 3	C	1957	262	251
" " 4	C	1963	520	510
Zion 1	N	1973	1,040	1,040
" 2	N	1974	1,040	1,040

2

[a] KEY: N = Nuclear, C = Coal, O = Oil, P = Peaking, and D = Diesel.

[b] The capability figures indicate CECo's 3/4 ownership of Quad Cities Station; Iowa-Illinois Gas & Electric's 1/4 interest represents a 39? MW and 385 MW capability for winter and summer, respectively. 1 2

Revision 1
5/79

Revision 2
8/79

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TABLE 1.1-2

ACTUAL COMMONWEALTH EDISON COMPANY SYSTEM

PEAK LOADS AND OUTPUT

DATE	PEAK LOAD (MW)	SALES (MW)	TOTAL PEAK LOAD (MW)	OUTPUT (1,000 x MWh)
1962 (Aug. 24)	5,281	78	5,359	28,165
1963 (July 1)	5,527	94	5,621	30,037
1964 (Aug. 3)	6,291	115	6,406	32,352
1965 (July 23)	6,671	97	6,768	34,788
1966 (July 12)	7,491	150	7,641	38,189
1967 (June 15)	7,643	255	7,898	40,018
1968 (Aug. 23)	8,950	92	9,042	43,457
1969 (July 16)	9,265	154	9,419	46,972
1970 (July 2)	10,027	67	10,094	49,751
1971 (June 28)	10,943	30	10,973	52,144
1972 (Aug. 18)	11,750	241	11,991	56,063
1973 (Aug. 27)	12,462	241	12,703	60,058
1974 (July 19)	12,270	80	12,350	59,274
1975 (Aug. 1)	12,305	40	12,345	60,310
1976 (July 14)	12,907	59	12,966	62,567
1977 (July 15)	13,932	132	14,064	65,110
1978 (Sept. 8)	13,720	57	13,777	67,927

2

TABLE 1.1-3

ESTIMATED COMMONWEALTH EDISON COMPANY SYSTEM

PEAK LOADS AND OUTPUT

DATE	PEAK LOAD (MW)	SALES (MW)	TOTAL PEAK LOAD (MW)	OUTPUT (1,000 x MWh)	
1979	15,070	--	15,070	71,060	
1980	15,760	--	15,760	74,330	
1981	16,480	--	16,480	77,750	
1982	17,230	300	17,530	81,400	
1983	18,010	--	18,010	85,230	
1984	18,820	--	18,820	89,240	
1985	19,660	--	19,660	93,430	
1986	20,530	225	20,755	97,820	
1987	21,430	--	21,430	102,420	
1988	22,360	--	22,360	107,230	
1989	23,320	--	23,320	112,270	2
1990	24,320	--	24,320	117,550	
1991	25,370	--	25,370	123,070	
1992	26,460	--	26,460	128,850	
1993	27,600	--	27,600	134,910	
1994	28,790	--	28,790	141,250	
1995	30,030	--	30,030	147,890	
1996	31,320	--	31,320	154,840	
1997	32,670	--	32,670	162,120	
1998	34,070	--	34,070	169,740	
1999	35,540	--	35,540	177,720	
2000	37,070	--	37,070	186,070	

[a] Peak load estimates through 1988 are based on econometric modeling. Peak load estimates beyond 1988 are based on extrapolation of econometric model results.

TABLE 1.1-4

COMMONWEALTH EDISON COMPANY ANNUAL LOAD DURATION CURVE FOR 1978

PERCENT OF PEAK LOAD	MINIMUM HOURS	PERCENT OF PEAK LOAD	MINIMUM HOURS	PERCENT OF PEAK LOAD	MINIMUM HOURS	PERCENT OF PEAK LOAD	MINIMUM HOURS	
1	8,760	26	8,760	51	5,420	76	476	
2	8,760	27	8,760	52	5,218	77	435	
3	8,760	28	8,760	53	5,019	78	389	
4	8,760	29	8,760	54	4,811	79	337	
5	8,760	30	8,759	55	4,634	80	297	
6	8,760	31	8,759	56	4,457	81	259	
7	8,760	32	8,757	57	4,267	82	233	
8	8,760	33	8,754	58	4,067	83	217	
9	8,760	34	8,729	59	3,869	84	188	
10	8,760	35	8,695	60	3,658	85	168	
11	8,760	36	8,663	61	3,412	86	141	
12	8,760	37	8,580	62	3,131	87	119	2
13	8,760	38	8,498	63	2,819	88	102	
14	8,760	39	8,362	64	2,495	89	83	
15	8,760	40	8,170	65	2,253	90	69	
16	8,760	41	7,966	66	2,000	91	54	
17	8,760	42	7,717	67	1,784	92	47	
18	8,760	43	7,488	68	1,542	93	38	
19	8,760	44	7,229	69	1,330	94	28	
20	8,760	45	7,003	70	1,136	95	21	
21	8,760	46	6,779	71	927	96	15	
22	8,760	47	6,537	72	786	97	13	
23	8,760	48	6,238	73	695	98	8	
24	8,760	49	5,946	74	609	99	5	
25	8,760	50	5,662	75	546	100	1	

Notes: Maximum Load for Period: 13,720 MW.
Maximum Load Occurred on: September 8.
Minimum Load for Period: 4,013 MW.
Minimum Load Occurred on: May 21.
Total Energy for Period: 68,099,944 MWh.
Load Factor for Period: 56.7 percent.

TABLE 1.1-5

MONTHLY SUMMARY FOR 1978

MONTH	MAXIMUM LOAD (MW)	MINIMUM LOAD (MW)	MEAN LOAD (MW)	LOAD FACTOR	ENERGY (TWH)	PERCENTAGE OF YEAR'S MAXIMUM
Jan.	10,726	5,180	8,100	0.755	6.03	78.18
Feb.	10,057	5,780	8,090	0.804	5.44	73.30
Mar.	9,600	5,260	7,541	0.785	5.61	69.97
Apr.	9,014	4,666	6,952	0.771	5.01	65.70
May	10,969	4,013	7,253	0.661	5.40	79.95
June	12,851	4,342	7,914	0.616	5.70	93.67
July	13,517	4,599	8,110	0.600	6.03	98.52
Aug.	13,675	4,640	8,538	0.624	6.35	99.67
Sept.	13,720	4,526	8,227	0.600	5.92	100.00
Oct.	9,152	4,562	7,114	0.777	5.29	66.71
Nov.	10,284	4,695	7,489	0.728	5.39	74.96
Dec.	10,423	5,254	7,969	0.765	5.93	75.97
Year	13,720	4,013	7,774	0.567	68.10	---

TABLE 1.1-6

LOAD CHARACTERISTICS ON COMMONWEALTH EDISON COMPANY

SYSTEM'S PEAK DAY: SEPTEMBER 8, 1978 2

PERCENT OF PEAK LOAD	MINIMUM HOURS OF DURATION	PERCENT OF PEAK LOAD	MINIMUM HOURS OF DURATION	PERCENT OF PEAK LOAD	MINIMUM HOURS OF DURATION	PERCENT OF PEAK LOAD	MINIMUM HOURS OF DURATION
1	24	26	24	51	24	76	14
2	24	27	24	52	22	77	14
3	24	28	24	53	21	78	14
4	24	29	24	54	20	79	14
5	24	30	24	55	20	80	13
6	24	31	24	56	20	81	13
7	24	32	24	57	18	82	12
8	24	33	24	58	18	83	12
9	24	34	24	59	18	84	12
10	24	35	24	60	18	85	12
11	24	36	24	61	17	86	12
12	24	37	24	62	17	87	10
13	24	38	24	63	17	88	10
14	24	39	24	64	17	89	10
15	24	40	24	65	17	90	10
16	24	41	24	66	17	91	9
17	24	42	24	67	16	92	8
18	24	43	24	68	16	93	7
19	24	44	24	69	16	94	5
20	24	45	24	70	16	95	5
21	24	46	24	71	16	96	5
22	24	47	24	72	15	97	5
23	24	48	24	73	15	98	4
24	24	49	24	74	15	99	3
25	24	50	24	75	14	100	1

2

Notes: Maximum Load for Period: 13,720 MW.
Minimum Load for Period: 7,025 MW.
Total Energy for Period: 258,550 MWh.
Load Factor for Period: 78.5 percent.

TABLE 1.1-7

ACTUAL AND LONG RANGE ESTIMATED SYSTEM PEAK LOADS AND OUTPUT REQUIRED FOR SALES TO ULTIMATE CONSUMERS AND MUNICIPALITIES FOR YEARS 1960 TO 2000

YEAR	PEAK LOAD (MW)	INCREASE OVER PREVIOUS YEAR		OUTPUT[a,b] (GWh)	PERCENT INCREASE OVER PREVIOUS YEAR	ANNUAL LOAD FACTOR
		MEGAWATTS	PERCENT			
1960	4,726	300	6.8	24,822	5.1	59.8
1961	4,970	244	5.2	26,178	5.5	60.1
1962	5,281	311	6.3	28,165	7.6	60.9
1963	5,527	246	4.7	30,037	6.6	62.0
1964	6,291	764	13.8	32,352	7.7	58.5
1965	6,671	380	6.0	34,788	7.5	59.5
1966	7,491	820	12.3	38,189	9.8	58.2
1967	7,643	152	2.0	40,018	4.8	59.8
1968	8,950	1,307	17.1	43,457	8.6	55.3
1969	9,265	315	3.5	46,972	8.1	57.9
1970	10,027	762	8.2	49,751	5.9	56.6
1971	10,943	916	9.1	52,144	4.8	54.4
1972	11,750	807	7.4	56,063	7.5	54.3
1973	12,462	712	6.1	60,058	7.1	55.0
1974	12,270	192[c]	1.5[c]	59,274	1.3[c]	55.1
1975	12,305	35	0.3	60,310	1.7	56.0
1976	12,907	602	4.9	62,567	3.7	55.2
1977	13,932	1,025	7.9	65,110	4.1	53.3
1978	13,720	212[c]	1.5[c]	67,927	4.3	56.5
---------------ESTIMATED[d]---------------				---------------ESTIMATED[d]---------------		
1979	15,070	1,350	9.8	71,060	4.6	53.8
1980	15,760	690	4.6	74,330	4.6	53.8
1981	16,480	720	4.6	77,750	4.6	53.9
1982	17,230	750	4.6	81,400	4.7	53.9
1983	18,010	780	4.5	85,230	4.7	54.0
1984	18,820	810	4.5	89,240	4.7	54.1
1985	19,660	840	4.5	93,430	4.7	54.2
1986	20,530	870	4.4	97,820	4.7	54.4
1987	21,430	900	4.4	102,420	4.7	54.6
1988	22,360	930	4.3	107,230	4.7	54.7
1989	23,320	960	4.3	112,270	4.7	55.0
1990	24,320	1,000	4.3	117,550	4.7	55.2
1991	25,370	1,050	4.3	123,070	4.7	55.4
1992	26,460	1,090	4.3	128,850	4.7	55.6
1993	27,600	1,140	4.3	134,910	4.7	55.8
1994	28,790	1,190	4.3	141,250	4.7	56.0
1995	30,030	1,240	4.3	147,890	4.7	56.2
1996	31,320	1,290	4.3	154,840	4.7	56.4
1997	32,670	1,350	4.3	162,120	4.7	56.6
1998	34,070	1,400	4.3	169,740	4.7	56.9
1999	35,540	1,470	4.3	177,720	4.7	57.1
2000	37,070	1,530	4.3	186,070	4.7	57.3

[a] Output estimates are based on a 365-day year.

[b] Excludes Lincoln and Albion.

[c] Decrease.

[d] Peak load estimates through 1988 are based on econometric modeling. Peak load estimates beyond 1988 are based on extrapolation of econometric model results. Estimates for the period 1979 through 1988 were approved February 6, 1979. The 1989 through 2000 estimates were based on simple extrapolation and were not the result of rigorous analyses.

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TABLE 1.1-8

DESCRIPTION OF MODEL I

Two equation (base load and weather-sensitive load) model of summer peak load. Observations for highest and second-highest summer loads are used. Dependent variables and FRB Index are are entered in logarithmic form; other variables, in raw form.

METHOD OF ESTIMATION

Ordinary least squares regression.

GENERAL FORM OF MODEL EQUATION

$$\log_{10}(BL_t) = a_o + a_1\, YRDY_t + a_2 \log_{10}(FRB_t) + u_t$$

$$\log_{10}(WSL_t) = b_o + b_1\, G^N + b_2\, CCDD32_t + b_3\, PCDD32_t + b_4\, SPCDD32_t + b_5\, TPCDD32_t + b_6\, MDBT2PD_t + b_7\, MINAMT_t + b_8\, RH2HR_t + b_9\, TAP_t + b_{10}\, WIND24_t + b_{11}\, DBT2HRS_t + u_t$$

EXPLANATORY VARIABLES USED IN MODEL

VARIABLE	DESCRIPTION
YRDY	yyddd, where year = 19yy and ddd = day #/365
FRB	FRB Index of Industrial Production, non-seasonally adjusted.
CCDD32	Cooling Degree Days, 24 hours ending 2 PM on day of peak.
PCDD32	Cooling Degree Days, 24 hours ending 2 PM on 1st day before peak.
SPCDD32	Cooling Degree Days, 24 hours ending 2 PM on 2nd day before peak.
TPCDD32	Cooling Degree Days, 24 hours ending 2 PM on 3rd day before peak.
MDBT2PD	Max. dry bulb temperature on 2nd day before peak.
MINAMT	Min. dry bulb temperature on morning of peak day.
DBT2HRS	Dry bulb temperature 2 hours prior to end of peak.
RH2HRS	Relative humidity 2 hours prior to end of peak.
TAP	Dry bulb temperature at end of peak.
WIND24	24-hour average wind speed on peak day.
G^N	Air conditioning saturation variable. G = Gompertz value. N = YRDY x 100-58.622 (effectively, years elapsed since August 15, 1958).

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902115

TABLE 1.1-9

MODEL I USING 1959-1978 OBSERVATIONS

EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Base Load	Intercept	1.77525	28.20242	0.06295
	Year and Day Number	0.88673	5.53392	0.16024
	FRB Index of Industrial Production	0.69129	8.28587	0.08343

NOTE: $R^2 = 0.9914$
Standard Error = 0.0122

EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Weather Sensitive Load	Intercept	3.14832	5.70252	0.55209
	Current Day CDD[a]	0.01598	1.90230	0.00840
	CDD[a] First Day Before Peak	0.00261	0.50742	0.00514
	CDD[a] Second Day Before Peak	0.00404	1.07699	0.00375
	CDD[a] Third Day Before Peak	0.00066	0.26289	0.00253
	Maximum DBT[b] Second Day Before Peak	-0.00028	-0.10541	0.00268
	Minimum DBT[b] on Morning of Peak Day	-0.00453	-1.54758	0.00293
	Relative Humidity 2 Hours Before End of Peak	0.00168	1.26500	0.00133
	DBT[b] at End of Peak	0.00126	0.27349	0.00462
	Wind Speed, 24-Hour Average on Peak Day	-0.00211	-0.58858	0.00359
	DBT[b] 2 Hours Before End of Peak	0.00901	1.54080	0.00585
	Modified Year and Day Number	-1.34515	-33.98080	0.03959

NOTE: $R^2 = 0.9822$
Standard Error = 0.0421

[a]Cooling Degree Days (CDD) for a 24-hour period ending at 2 p.m. on the day in question.

[b]Dry Bulb Temperature (DBT).

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TABLE 1.1-10

20-YEAR (1959-1978) AVERAGE PEAK-MAKING WEATHER VALUES

USED IN MODEL I FOR FORECASTING

	VARIABLE	VALUE
1.	Current Day Cooling-Degree-Days[a]	17.85
2.	First Previous Day Cooling-Degree-Days[a]	15.29
3.	Second Previous Day Cooling-Degree-Days[a]	12.85
4.	Third Previous Day Cooling-Degree-Days[a]	12.68
5.	Maximum Temperature Second Previous Day	89.1°F
6.	Minimum Morning Temperature	75.4°F
7.	Wind, 24-Hour Average	9.0 mph
8.	Temperature 2 Hours before Peak Load Occurrence	91.85°F
9.	Relative Humidity 2 Hours before Peak	51.35%
10.	Temperature at Time of Peak	93.8°F

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[a]Degree days are calculated for the 24-hour period ending at 2 p.m. on the day in question.

TABLE 1.1-11

DESCRIPTION OF MODEL III

This is a peak load model with base load and peak load equations. Variables are expressed as the first difference of their natural logarithms (Dln). Observations for June, July, and August peak days are used.

METHOD OF ESTIMATION

Model III is estimated with two-stage least squares (2SLS).

GENERAL FORM OF MODEL EQUATION

BASE LOAD

$$\begin{aligned} \mathrm{Dln\ (Base\ MW)}_t = {} & a_o + a_1\mathrm{Dln(Cust)}_t + a_2\mathrm{Dln(GSP)}_t + a_3\mathrm{Dln(Pe)}_t \\ & + a_4\mathrm{Dln(Pe)}_{t-1} + a_5\mathrm{Dln(Pe)}_{t-2} + a_6\mathrm{Dln(Pe)}_{t-3} \\ & + a_7\mathrm{Dln(Pe)}_{t-4} + a_8\mathrm{Dummy} + u_t \end{aligned}$$

PEAK LOAD

$$\begin{aligned} \mathrm{Dln\ (Peak\ MW)}_t = {} & b_o + b_1\mathrm{Dln(Pe)}_t + b_2\mathrm{Dln(Base^*)}_t + b_3\mathrm{Dln(RH2HR)}_t \\ & + b_4\mathrm{Dln(TOTCDD)}_t + b_5\mathrm{Dln(DBT2HR)}_t + b_6\mathrm{Dln(ACSAT)}_t + u_t \end{aligned}$$ 2

where u_t = error term

EXPLANATORY VARIABLES USED IN MODEL

VARIABLE	DESCRIPTION	BASE	PEAK
Cust	Customer Index [illegible]ed to reflect growth of customers	x	
GSP	Illinois Gross State Product-used to measure income	x	
Pe_t	Real Price Index of Electricity-marginal price (measured at time t)	x	x
Pe_{t-1}-Pe_{t-4}	Pe lagged 1 to 4 years	x	
Dummy	Conservation dummy variable to reflect discontinuities in 1974-75	x	
Base*	Estimated base load from 1st stage base load equation		x
RH2HR	Relative humidity 2 hours prior to peak		x
TOTCDD	Total CDD from May 15 to date of observation		x
DBT2HR	Dry bulb temperature 2 hours prior to peak		x
ACSAT	Air conditioning saturation index		x

TABLE 1.1-12

MODEL III: EXPLANATORY VARIABLE DEFINITIONS

Real Price Index of Electricity to all CECo Customers (Price):

Most CECo customers fall into one of three classes: residential, small commercial and industrial (SC&I), and large commercial and industrial (LC&I). These three customer classes comprise well over 90 percent of the load on any summer peak day. A marginal or incremental price is computed for a representative customer of each class, using August 1 rates for the year in question. The residential customer's incremental price is considered the tail block of Rate 1; the SC&I's price is the energy charge at 1,500 KWH under Rate 6 plus the charge in lieu of demand; and the LC&I's price is the energy charge at 1,600,000 KWH and the incremental demand charge using a 56 percent load factor assumption under Rate 6. The fuel adjustment charge and state tax are added to the price charged to all three customer classes. 2

The prices to the three customer classes are combined using a weighted average. Each weight represents an estimate of a class's percent contribution in kilowatts to the 1967 summer peak, normalized so that the sum of the weights equals one. The nominal price is then divided by an index of the average price of all other goods and services (e.g., CPI, 1967=100) in order to arrive at a real price. This real price is indexed such that 1967=100.

Price Lagged 1, 2, 3, and 4 Years:

The above Real Price Index of Electricity for each of the 4 years preceding the year in question.

Illinois Gross State Product:

The Illinois Department of Business and Economic Development publishes a historical series on the Illinois Gross State Product deflated to 1972 dollars. This "income" variable is used to

TABLE 1.1-12 (Cont'd) Page 2 of 2

represent the gross income of Commonwealth Edison customers, thereby reflecting their addition of more electrical appliances and housing, an improved standard of living, increased commercial and industrial activity, etc.

Customer Index:

Customers are divided into three classes: residential customers, commercial and industrial customers inside Chicago, and commercial and industrial customers outside Chicago. Indexes reflecting the change over time in the number of customers in each class are combined to obtain a weighted average index. The weights applied to each class are based on that class's contribution to the base load peak, thereby accounting for the per customer contribution and the relative size of a customer class. 2

Dummy Variable for Low Base Load Observations in 1974 and 1975:

This variable is set to one in the base load equation for 1974 and 1975 observations and to zero for all other observations. This variable attempts to reflect the discontinuities of 1974 and 1975 brought about by the Arab oil embargo.

Air Conditioning Saturation:

The air conditioning saturation values are estimates of the percent of CECo residential customers that have the equivalent of central electric air conditioning.

Three Weather Variables:

(1) Dry Bulb Temperature 2 hours prior to peak load occurrence.

(2) Relative Humidity 2 hours prior to peak load occurrence.

(3) Cumulative Cooling Degree Days (CDD) from May 15. The number of CDD are totaled from May 15 through the peak demand day in June, July, and August for the years 1959 through 1978.

902120

TABLE 1.1-13

MODEL III USING 1959-1978 OBSERVATIONS

EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Base Load	Intercept	4.55432	11.85343	0.38422
	Illinois Gross State Product	0.14866	1.43740	0.10342
	Customer Index	0.05907	0.32068	0.18421
	Dummy Variable	-3.39269	-4.18139	0.81138
	Real Price Index of Electricity	-0.09154	-1.47607	0.06201
	Price Lagged 1 Year	-0.02591	-0.44133	0.05872
	Price Lagged 2 Years	-0.02428	-0.55044	0.04411
	Price Lagged 3 Years	-0.12311	-2.74484	0.04485
	Price Lagged 4 Years	-0.02922	-0.64235	0.04549

NOTE: R^2 = .6683
Standard Error = 1.3743

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EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Peak Load	Intercept	-0.91342	-0.36267	2.51858
	Base Load	1.06100	2.14748	0.49407
	Real Price Index of Electricity	0.20932	0.80455	0.26017
	Dry Bulb Temperature 2 Hours Before Peak	0.71509	4.20373	0.17011
	Total Cooling Degree Days Since May 15	0.05846	2.77946	0.02103
	Relative Humidity 2 Hours Before Peak	-0.01242	-0.31357	0.03960
	Air Conditioning Saturation	0.19559	1.59612	0.12254

NOTE: R^2 is not defined when using 2-stage least squares estimation
Standard Error = 4.8786

TABLE 1.1-14

DESCRIPTION OF MODEL IV

Two equation model, one for base load and the other for weather-sensitive load. Each year enters monthly peak data for June, July, and August. Observations are expressed as first difference of the natural logarithms.

METHOD OF ESTIMATION

Seemingly Unrelated Regression.

GENERAL FORM OF MODEL EQUATION

$$\text{Dln (MW)} = b_o + b_1\, \text{Dln}(X_1)_t + b_2\, \text{Dln}(X_2)_t + \cdots + b_n \text{Dln}(X_N)_t + u_t$$

b = coefficients determined by regression

X = independent variables

Dln = difference in natural logarithms of two observations 1 year apart

u = error term

MW = dependent variable (base load or weather sensitive load)

EXPLANATORY VARIABLES USED IN MODEL 2

VARIABLE	DESCRIPTION	BASE	WEATHER SENSITIVE
Electric Price	Average real price of electricity across all customer classes. Use current value and lagged 1, 2, 3 and 4 years.	x	
Economic	Illinois Gross State Product-used as measure of income.	x	
Gas Price	Average real price of natural gas in Illinois.	x	
Population	Weighted average customer growth index.	x	
Dummy	Reflects discontinuities of 1974 and 1975.	x	
A/C Saturation	Number of customers with some form of air conditioning.		x
Weather	Cumulative CDD from May 15, 4-day weighted average THI at time of peak.		x
Dummy	Reflects discontinuities of 1964 and 1965.		x

TABLE 1.1-15 Page 1 of 2

MODEL IV: EXPLANATORY VARIABLE DEFINITIONS

Real Price Index of Electricity to all CECo Customers (Price):

An average cost per KWH is computed for several representative customers in the residential, small commercial and industrial, and large commercial and industrial classes, using August 1 rates for the year in question. These costs are then weighted to obtain an average cost per KWH for each class. The fuel adjustment charge and state tax are added to the price charged to all three customer classes.

The prices to the three customer classes are combined and indexed in a manner similar to the marginal price described in the Model III write-up, page II-11a. 2

Price Lagged 1, 2, 3, and 4 Years:

The above Real Price Index of Electricity for each of the 4 years preceding the year in question.

Illinois Gross State Product (Income):

See Model III write-up, Table 1.1-12.

Dummy Variable for Low Base Load Observations in 1974 and 1975:

See Model III write-up, Table 1.1-12.

Real Price Index of Natural Gas in Illinois:

The industry average price ($/MMBTU) of natural gas in Illinois is divided by an index of the average price of all other goods and services (CPI, 1967=100) to obtain the real price. This series is indexed such that 1967=100.

TABLE 1.1-15 (cont'd) Page 2 of 2

Residential Air Conditioning Saturation:

The air conditioning saturation values (as defined in Model III write-up, Table 1.1-12) are multiplied by the number of residential customers.

Dummy Variable to Account for Unusual Weather Sensitive Load Observations in August of 1963 and 1964:

This variable is set to one in the weather sensitive load equation for the August 1963 and August 1964 observations and to zero for all other observations. 2

Two Weather Variables:

(1) Cumulative Cooling Degree Days (CDD) from May 15: See Model III write-up, Table 1.1-12.

(2) Four-Day Weighted Average Temperature Humidity Index (THI): The second weather variable is the THI at the time of the system peak and the THI's at the hour of the daily peaks 1, 2, and 3 days before the system peak. Weights are developed and applied to each of the four THI observations in June, July, and August for the years 1959 through 1978 to provide a representation of short-term heat buildup.

TABLE 1.1-16

MODEL IV USING 1959-1978 OBSERVATIONS

EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Base Load	Intercept	4.11406	10.17209	0.40445
	Customer Index	0.07140	0.54057	0.13208
	Illinois Gross State Product	0.21402	2.81291	0.07609
	Real Price Index of Natural Gas	-0.05259	-1.11227	0.04729
	Dummy Variable	-2.87207	-4.27288	0.67216
	Real Price Index of Electricity	-0.12562	-1.63063	0.07704
	Price Lagged 1 Year	-0.02999	-0.32858	0.09126
	Price Lagged 2 Years	-0.00275	-0.03913	0.07031
	Price Lagged 3 Years	-0.18336	-2.50819	0.07310
	Price Lagged 4 Years	-0.06748	-0.88336	0.07639

NOTE:[a] $R^2 = 0.7146$
Standard Error = 1.2882

EQUATION	VARIABLE	REGRESSION COEFFICIENT	T-STATISTIC	STANDARD ERROR
Weather Sensitive Load	Intercept	1.65186	0.42385	3.89732
	Total Cooling Degree Days Since May 15	0.14150	3.20391	0.04416
	Temperature Humidity Index	3.61464	9.12339	0.39619
	Air Conditioning Saturation	0.56109	2.05919	0.27248
	Dummy Variable	17.92445	1.85423	9.66679

NOTE:[a] $R^2 = 0.6395$
Standard Error = 14.7392

[a] R^2 and Standard Errors are those derived from direct least squares.

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TABLE 1.1-17

ASSUMPTIONS USED ON EXPLANATORY VARIABLES

		GROWTH RATE
1.	Illinois Gross State Product: Extension of 1972-1977 average annual compounded growth rate	2.27%
2.	Federal Reserve Board Index of Industrial Production: Extension of 1968-1978 average annual compounded growth rate	3.14%
3.	Customer Index	1.50%
	a. Residential	1.48%
	b. C&I inside Chicago	-1.13%
	c. C&I outside Chicago	2.50%
	Residential from Illinois Bureau of Budget household projections; Inside from Box-Jenkins; Outside from Box-Jenkins.	
4.	Real Price of Electricity: Marginal; 1979 was adjusted for the effect of a proposed 5.9% rate increase and for a seasonal residential rate	-2.7% in 1979 1% thereafter
	Average: 1979 was adjusted for the effect of a proposed 5.9% rate increase and for a seasonal residential rate.	3.2% in 1979 1% thereafter
5.	Real Price of Natural Gas: Based on the roll in of new gas	4.8%
6.	a. Air Conditioning Saturation Index used in Model III: For 1978: Derived by fitting an S-shaped curve to the 1960-1983[a] A/C saturation data.	3.47% in 1979 and gradually declining to 1.15% in 1988
	b. Air Conditioning Saturation Index used in Model IV: Air conditioning saturation values times the number of residential customers. For 1978: Derived by fitting an S-shaped curve to the 1960-1983 saturation data and multiplying them by the number of residential customers growing at 1.48% year.[a]	4.94% in 1979 and gradually declining to 2.66% in 1988
7.	Weather	20-year average peak-making weather

Note: Annual compounded growth rates.

[a]Results of air conditioning survey conducted by Burke Marketing Research were used to calibrate Gompertz curve of A/C Saturation.

902126

TABLE 1.1-18

GROWTH MATRIX: 10-YEAR PEAK LOAD FORECAST BASED ON VARIOUS COMBINATIONS OF BASE AND WEATHER SENSITIVE GROWTH RATES

WEATHER SENSITIVE LOAD GROWTH RATE	BASE LOAD GROWTH RATE 2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0
3.0	2.7	3.0	3.3	3.6	3.9	4.2	4.6	4.9
3.5	2.9	3.2	3.5	3.8	4.1	4.4	4.7	5.1
4.0	3.1	3.4	3.7	4.0	4.3	4.6	4.9	5.2
4.5	3.3	3.6	3.9	4.2	4.5	4.8	5.1	5.4
5.0	3.6	3.8	4.1	4.4	4.7	5.0	5.3	5.6
5.5	3.8	4.1	4.3	4.6	4.9	5.2	5.5	5.8
6.0	4.0	4.3	4.6	4.8	5.1	5.4	5.7	6.0
6.5	4.3	4.5	4.8	5.1	5.3	5.6	5.9	6.2
7.0	4.5	4.8	5.0	5.3	5.6	5.8	6.1	6.4
7.5	4.7	5.0	5.3	5.5				
8.0	5.0	5.2	5.5	5.7				
8.5	5.3	5.5						
9.0	5.5							

Note: A peak load growth rate of 4.4 to 4.6 percent can be achieved with several different reasonable combinations of base load growth and weather sensitive load growth.

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TABLE 1.1-19

GROWTH PROJECTIONS MADE BY OTHERS[a]

	PREVIOUS	CURRENT
Real GNP		
Wharton	3.5%	3.0%
Data Resources Inc.	3.2 - 3.5%	2.6 - 3.6%
Electrical World	3.5%	3.7%
Industrial Production		
Data Resources Inc.	3.8 - 3.9%	2.9 - 4.5%
Electrical World	3.8%	3.7%
Electrical Output (KWH)		
Electrical World	4.8%	4.0%
A.D. Little	-	4.1%
Peak Electrical Load (KW)		
Electrical World	5.7%	4.8%
Westinghouse ('77-'85)	-	4.6%
Westinghouse ('77-'2000)	-	4.1%
National Electric Reliability Council	-	5.2%

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[a]10-year compound annual rates unless otherwise noted.

TABLE 1.1-20

COMMONWEALTH EDISON COMPANY SUMMER PEAK LOAD FORECASTS: 1966-1988

YEAR	SUMMER PEAK LOAD (MW)	DATE OF ESTIMATE												
		12-12-66	3-18-68	3-1-69	4-17-69	11-25-70	6-16-72	10-18-72	5-7-74	10-2-74	9-30-75	11-5-76	10-28-77	2-6-79
1966	7,491	-												
1967	7,643	8,033	-											
1968	8,950	8,640	8,700	-										
1969	9,265	9,287	9,390	9,590	-									
1970	10,027	9,974	10,130	10,380	10,380	-								
1971	10,943	10,921	10,960	11,260	11,260	11,110	-							
1972	11,750	11,527	11,840	12,190	12,190	12,190	12,190	-						
1973	12,462	12,393	12,780	13,180	13,180	13,180	12,830	12,750	-					
1974	12,270		13,780	14,230	14,230	14,230	13,880	13,760	13,310	-				
1975	12,305		14,840	15,340	15,340	15,340	14,990	14,810		13,500	-			
1976	12,907			16,540	16,540	16,540	16,170	15,940		14,540	13,500	-		
1977	13,932				17,760	17,760	17,430	17,130		15,630	14,310	13,990	-	
1978					19,060	19,060	18,800	18,410		16,680	15,380	14,870	14,450	-
1979					20,410	20,410	20,250	19,760		17,780	16,460	15,790	15,220	15,070
1980						21,820	21,810	21,210		18,930	17,550	16,770	16,020	15,760
1981							23,470	22,730		20,130	18,690	17,800	16,850	16,480
1982								24,350		21,390	19,870	18,880	17,720	17,230
1983								26,050		22,700	21,120	20,010	18,620	18,010
1984										24,080	22,410	21,210	19,560	18,820
1985										25,490	23,780	22,470	20,540	19,660
1986												23,790	21,560	20,530
1987													22,610	21,430
1988														22,360

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Notes: Forecasts made before 1966 are not included since adjustments to exclude Central Illinois Electric & Gas division for each forecast before 1966 are not available.

Values exclude Lincoln and Albion loads.

TABLE 1.1-21

COMMONWEALTH EDISON COMPANY SUMMER PEAK LOAD FORECASTS AS PERCENTAGES OF ACTUAL PEAK LOADS: 1966-1978

YEAR	SUMMER PEAK LOAD (MW)	DATE OF ESTIMATE 12-12-66	3-18-68	3-1-69	4-17-69	11-25-70	6-16-72	10-18-72	5-7-74	10-2-74	9-30-75	11-5-76	10-28-77	2-6-79
1966	7,491	100												
1967	7,643	105.1	100											
1968	8,950	96.5	97.2	100										
1969	9,265	100.2	100.3	103.5	100									
1970	10,027	99.5	101.0	103.5	103.5	100								
1971	10,943	98.0	100.2	102.9	102.9	101.5	100							
1972	11,750	98.1	100.8	103.7	103.7	103.7	103.7	100						
1973	12,462	99.4	102.6	105.8	105.8	105.8	103.0	102.3	100					
1974	12,270	-	112.3	116.0	116.0	116.0	113.1	112.1	108.5	100				
1975	12,305	-	120.6	124.7	124.7	124.7	121.8	120.4	-	109.7	100			
1976	12,907	-	-	128.1	128.1	128.1	125.3	123.5	-	112.7	104.6	100		
1977	13,932	-	-	-	127.5	127.5	125.1	123.0	-	112.2	102.7	100.4	100	
1978	13,720	-	-	-	138.9	138.9	137.0	134.0	-	121.6	112.1	108.4	105.3	100

Notes: Estimates as percentages of actual peak loads made before 1966 are not included since adjustments to exclude Central Illinois Electric & Gas division for each forecast before 1966 are not available.

Values exclude Lincoln and Albion loads.

2

2

TABLE 1.1-22

COMMONWEALTH EDISON COMPANY SUMMER PEAK LOAD FORECASTS AS PERCENTAGES

OF RECONSTRUCTED PEAK LOADS: 1966-1978

YEAR	RECONSTRUCTED SUMMER PEAK LOAD (MW)[a]	DATE OF ESTIMATE												
		12-12-66	3-18-68	3-1-69	4-17-69	11-25-70	6-16-72	10-13-72	5-7-74	10-2-74	9-30-75	11-5-76	10-28-77	2-6-79
1966	7,651	100												
1967	7,851	102.3	100											
1968	9,195	94.0	94.6	100										
1969	9,358	99.2	100.3	102.5	100									
1970	10,365	96.2	97.7	100.1	100.1	100								
1971	11,088	96.7	98.8	101.6	101.6	100.2	100							
1972	11,830	97.4	100.1	103.0	103.0	103.0	103.0	100						
1973	12,859	96.4	99.4	102.5	102.5	102.5	99.8	99.2	100					
1974	12,416	-	111.0	114.6	114.6	114.6	111.8	110.8	107.2	100				
1975	12,499	-	118.7	122.7	122.7	122.7	119.9	118.5	-	108.0	100			
1976	13,116	-	-	126.1	126.1	126.1	123.4	121.5	-	110.9	102.9	100		
1977	14,230	-	-	-	124.8	124.8	122.5	120.4	-	109.8	105.6	98.3	100	
1978	13,720	-	-	-	138.9	138.9	137.0	134.2	-	121.6	112.1	108.4	105.3	100

Note: Values exclude Lincoln and Albion loads.

[a] Reconstructed according to Table 1.1-18.

TABLE 1.1-23

RECONSTRUCTED ANNUAL PEAK

DATE	ACTUAL PEAK	VACATIONS	VOLTAGE REDUCTION	RIDER 17[a]	OTHER[b]	RECONSTRUCTED PEAK[c]	
8-25 1959	4,299	-7	0	0	-200	4,506	
9-8 1960	4,726	0	0	0	0	4,726	
8-31 1961	4,970	-20	0	0	0	4,990	
8-24 1962	5,281	-16	0	0	0	5,297	
7-1 1963	5,527	-149	0	0	0	5,676	2
8-3 1964	6,291	-81	0	0	0	6,372	
7-23 1965	6,671	-139	0	0	0	6,810	
7-12 1966	7,491	-117	0	0	-43	7,651	
6-15 1967	7,643	-8	-150	-50	0	7,851	
8-23 1968	8,950	-60	-100	-10	-75	9,195	
7-16 1969	9,265	-123	0	0	0	9,388	2
7-2 1970	10,027	-142	-83	-12	-100	10,364	
6-28 1971	10,943	-145	0	0	0	11,088	
8-18 1972	11,750	-80	0	0	0	11,830	
8-27 1973	12,462	-17	-300	-80	0	12,859	
7-19 1974	12,270	-146	0	0	0	12,416	
8-1 1975	12,305	-194	0	0	0	12,499	
7-14 1976	12,907	-209	0	0	0	13,116	
7-15 1977	13,932	-238	0	-60	0	14,230	
9-8 1978	13,720	0	0	0	0	13,720	2

[a] Electric Furnace Interruptible Service.

[b] Strikes, voluntary load control, etc.

[c] Different reconstruction methods can provide varying results based on treatment of weather, vacations, and the passage of time.

902132

TABLE 1.1-24

OFFICIAL PEAK LOAD ESTIMATES
1979-1988

YEAR	LOW GROWTH RATE "C" MW	LOW GROWTH RATE "C" %	MOST LIKELY GROWTH RATE "B" MW	MOST LIKELY GROWTH RATE "B" %	HIGH GROWTH RATE "A" MW	HIGH GROWTH RATE "A" %
1979	15,000	4.2[a]	15,070	4.7[a]	15,140	5.1[a]
1980	15,620	4.1	15,760	4.6	15,910	5.1
1981	16,260	4.1	16,480	4.6	16,700	5.0
1982	16,920	4.1	17,230	4.6	17,530	5.0
1983	17,610	4.1	18,010	4.5	18,400	5.0
1984	18,320	4.0	18,820	4.5	19,310	4.9
1985	19,060	4.0	19,660	4.5	20,260	4.9
1986	19,820	4.0	20,530	4.4	21,250	4.9
1987	20,600	3.9	21,430	4.4	22,290	4.9
1988	21,400	3.9	22,360	4.3	23,370	4.8
1978-1988 Average Annual Compound Growth Rate		4.0		4.5		5.0

[a] Increase is based on a weather-adjusted, reconstructed peak load of 14,400 MW.

Actual Peak Load Recorded 9-8-78			13,720
Adjustments:	(a)	Load Curtailment	0
	(b)	Industrial Vacation	0
	(c)	Average Peak-Making Weather	+680
			14,400 MW

2

TABLE 1.1-25

FIRM POWER INTERCHANGES

AT TIMES OF ANNUAL PEAK DEMAND

YEAR	PURCHASES[a] (MW)	SALES (MW)	NET RECEIVED (MW)
1962	0	78	-78
1963	0	94	-94
1964	300	115	185
1965	150	97	53
1966	0	150	-150
1967	100	255	-155
1968	200	92	108
1969	700	154	546
1970	808	67	741
1071	750	30	720
1972	900	241	659
1973	880[b]	241	639
1974	1,324[c]	80	1,244
1975	1,324	40	1,284
1976	1,324	59	1,265
1977	1,324	132	1,192
1978[d]	1,124	90	1,034
1979	624	0	624
1980	624	0	624
1981	624	0	624
1982	624	0	624
1983	312	0	312
1984	312	0	312
1985	312	0	312
1986	312	0	312
1987	312	0	312
1988	0	0	0
1989	0	0	0

[a] All purchases indicated are contracted purchases.

[b] 520 MW of total from Ludington Pumped Hydro-Electric Station.

[c] 624 MW of total from Ludington Pumped Hydro-Electric Station.

[d] Values for 1978 and succeeding years are estimated.

TABLE 1.1-26

PLANNED NEW GENERATING UNITS

STATION - UNIT	NET CAPABILITY (MW) WINTER	SUMMER	PROJECTED SERVICE DATE	
Collins 1	515	515	April 1978	
Collins 4	505	505	December 1978	
Collins 5	505	505	June 1979	
La Salle County 1	1,078	1,048	December 1980	
La Salle County 2	1,078	1,048	December 1981	
Byron 1	1,120	1,120	October 1982	
Braidwood 1	1,120	1,090	October 1982	
Byron 2	1,120	1,120	October 1983	
Braidwood 2	1,120	1,090	October 1983	
Langham #2	550	550	April 1987	
Langham #1	550	550	October 1987	2
Unidentified Fossil	550	550	April 1988	
Unidentified Fossil	550	550	October 1988	
Unidentified Fossil	550	550	April 1989	
Unidentified Fossil	550	550	October 1989	
Unidentified Fossil	550	550	April 1990	
Carroll County 1[a]	840	817	October 1990	1
Unidentified Fossil	550	550	October 1990	
Unidentified Fossil	500	500	April 1991	
Carroll County 2[a]	840	817	October 1991	1
Unidentified Fossil	500	500	April 1992	

[a] Carroll County Units owned 75% by Commonwealth Edison Company and 25% jointly by Iowa-Illinois Gas & Electric and Interstate Power Co.; Net Capability figures represent CECo's 75% share. 1

Revision 1
5/79

Revision 2
8/79

902135

TABLE 1.1-27

GENERATING UNIT RETIREMENTS

STATION - UNIT	NET CAPABILITY (MW) WINTER	SUMMER	RETIREMENT DATE	
Fisk - 18	129	119	January 1978	
State Line - 1	171	171	January 1978	1
Waukegan - 5	122	122	January 1978	
Joliet - 5	85	85	February 1978	
Dixon - 4	52	50	July 1978	
Dixon - 5	67	65	July 1978	
State Line - 2	140	140	January 1979	
Ridgeland - 1	163	157	October 1990	
Ridgeland - 2	158	152	October 1990	
Ridgeland - 3	143	137	October 1990	2
Ridgeland - 4	142	136	October 1990	
Waukegan - 6	88	88	October 1991	

Revision 1
5/79

Revision 2
8/79

902136

TABLE 1.1-28

GENERATING UNIT CAPABILITIES AND ESTIMATED CAPACITY FACTORS: 1972-1991

PLANT NAME	UNIT	TYPE[a]	FUNCTION[b]	SUMMER CAPABILITY (MW) 1972	1973	1974	1975	1976	1977	1978	ESTIMATED 1979-1991 CAPACITY FACTORS IN PERCENT
Collins	2	F	C	0	0	0	0	0	0	510	25-30
	3	F	C	0	0	0	0	0	500	500	25-30
	1	F	C	0	0	0	0	0	500	515	25-30
Crawford	6	F	C	31	81	81	81	64	0	0	0
	7	F	C	222	222	222	222	219	219	219	40-50
	8	F	B	350	350	350	350	340	319	319	40-50
Dixon	4	F	C	50	50	50	50	50	50	0	0
	5	F	C	65	65	65	65	65	65	0	0
Dresden	1	N	B	200	200	200	200	197	197	197	55-65
	2	N	B	587	587	780	780	772	772	772	55-65
	3	N	B	0	0	786	780	773	773	773	55-65
Fisk	18	F	C	158	146	146	146	119	119	0	0
	19	F	B	336	336	336	336	336	336	336	40-50
	20	F	P	11	11	11	11	11	11	11	1- 3
Joliet	5	F	C	117	117	117	117	85	85	0	0
	6	F	B	334	334	334	334	330	330	330	35-45
	7	F	B	617	613	613	613	533	533	533	45-55
	8	F	B	617	613	613	613	533	533	533	45-55
	9	F	P	11	11	11	11	11	11	11	1- 3
Kincaid	1	F	B	616	616	616	616	606	606	606	45-55
	2	F	B	616	616	616	616	606	606	606	45-55
Powerton	1	F	P	60	60	60	0	0	0	0	0
	2	F	P	60	60	60	0	0	0	0	0
	3	F	P	113	99	99	0	0	0	0	0
	4	F	P	113	113	113	0	0	0	0	0
	5	F	B	0	850	850	850	850	850	850	50-60
	6	F	B	0	0	0	0	850	850	850	50-60
Quad Cities[c]	1	N	B	0	0	585	585	576	576	576	55-65
	2	N	B	0	0	585	585	577	577	577	55-65
Ridgeland	1	F	C	152	152	152	152	152	157	157	30- 0
	2	F	C	152	152	152	152	152	152	152	30- 0
	3	F	C	137	137	137	137	137	137	137	30- 0
	4	F	C	132	132	132	132	132	132	136	30- 0
Sabrooke	1	F	C	20	20	20	0	0	0	0	0
	2	F	C	34	34	34	0	0	0	0	0
	3	F	C	35	35	35	34	0	0	0	0
	4	F	C	57	57	57	57	57	0	0	0
State Line	1	F	C	206	206	206	206	171	171	0	0
	2	F	C	150	150	150	150	140	140	140	25- 0
	3	F	C	230	230	230	230	190	190	190	40-50
	4	F	B	358	358	358	358	318	318	318	40-50
Waukegan	1	F	P	20	0	0	0	0	0	0	0
	2	F	P	31	0	0	0	0	0	0	0
	3	F	P	50	0	0	0	0	0	0	0
	5	F	C	129	129	129	129	122	122	0	5- 0
	6	F	C	119	119	119	119	88	88	88	25-35
	7	F	B	338	338	338	338	310	328	328	40-50
	8	F	B	360	360	360	360	296	[illegible]	358	40-50
Will County	1	F	C	139	139	139	139	139	139	139	25-35
	2	F	C	148	148	148	148	148	161	161	25-35
	3	F	C	251	251	251	251	251	251	251	40-50
	4	F	B	513	513	513	513	503	510	510	40-50
Zion	1	N	B	0	0	880	880	1,040	1,040	1,040	55-65
	2	N	B	0	0	0	880	1,040	1,040	1,040	55-65
Peaking Units	-	F	P	1,602	1,602	1,602	1,602	1,467	1,463	1,463	2-10

[a]Abbreviations as follows: F - Fossil Unit; H - Hydroelectric Unit; N - Nuclear Unit.

[b]Abbreviations as follows: B - Base Load; C - Cyclic Load; P - Peaking Load.

[c]Quad Cities owned 75% by Commonwealth Edison Company and 25% by Iowa-Illinois Gas & Electric Company; values represent CECo's 75% share. 1

POOR ORIGINAL

Revision 1
5/79

Revision 2
8/79

902137

TABLE 1.1-29

GENERATING UNIT ADDITIONS: 1979-1992

YEAR AVAILABLE FOR SUMMER PEAK	PLANT NAME	UNIT (ABBR)	TYPE[a]	FUNCTION[b]	SUMMER CAPABILITY (RETIREMENTS)[c]	ESTIMATED CAPACITY FACTOR IN PERCENT FOR FIRST 10 YEARS
1979	Collins	4 (C4)	F	C	530	25-30
	Collins	5 (C5)	F	C	530	25-30
1981	La Salle	1 (LAS1)	N	B	1,048	60-70
1982	La Salle	2 (LAS2)	N	B	1,048	60-70
1983	Braidwood	1 (BR1)	N	B	1,090	60-70
	Byron	1 (BY1)	N	B	1,120	60-70
1984	Braidwood	2 (BR2)	N	B	1,090	60-70
	Byron	2 (BY2)	N	B	1,120	60-70
1987	Langham	2 (LAN2)	F	C	550	30-35
1988	Langham	1 (LAN1)	F	C	550	30-35
	Unidentified	1 (FOS)	F	C	550	30-35
1989	Unidentified	1 (FOS)	F	C	550	30-35
	Unidentified	1 (FOS)	F	C	550	30-35
1990	Unidentified	1 (FOS)	F	C	550	30-35
	Unidentified	1 (FOS)	F	C	550	30-35
1991	Carroll County[d]	1 (CC1)	N	B	817[e]	60-70
	Unidentified	1 (FOS)	F	C	550	30-35
	Unidentified	1 (FOS)	F	C	500	25-30
1992	Carroll County[d]	2 (CC2)	N	B	818[e]	60-70
	Unidentified	1 (FOS)	F	C	500	25-30

[a] Abbreviations as follows: F - Fossil Unit; H - Hydroelectric Unit; N - Nuclear Unit.

[b] Abbreviations as follows: B - Base Load; C - Cyclic Load; P - Peaking Load.

[c] Refer to Table 1.1-26 for Summer Capability Listings.

[d] Carroll County Units owned 75% by Commonwealth Edison Company and 25% by Iowa-Illinois Gas & Electric and Interstate Power Co.

[e] Represents CECo's 75% share

902138

TABLE 1.1-30

COMMONWEALTH EDISON COMPANY LOAD AND CAPACITY STATEMENT

CAPABILITY	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Net Additions & Retirements Since Previous Peak	1,026	0	1,078	1,078	2,240	2,240	0	0	550	1,100	1,100	1,100	1,284	1,252
Owned Net Generating Capacity	17,824	17,824	18,902	19,980	22,220	24,460	24,460	24,460	25,010	26,110	27,210	28,310	29,594	30,846
Less: Summer Limitations	534	534	564	594	624	654	654	654	654	654	654	654	653	675
Less: Firm Sales	0	0	0	300	0	0	0	225	0	0	0	0	0	0
Plus: Firm Pur. & Div. Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Plus: Ludington Purchase	624	624	624	624	312	312	312	312	312	0	0	0	0	0
NET CAPABILITY	17,914	17,914	18,962	19,710	21,908	24,118	24,118	23,893	24,668	25,456	26,556	27,656	28,941	30,171
LOAD														
Peak Load[a]	15,070	15,760	16,480	17,230	18,010	18,820	19,660	20,530	21,430	22,360	23,320	24,320	25,370	26,460
RESERVE-CARROLL COUNTY UNITS ON SCHEDULE														
Reserve Margin	2,844	2,154	2,482	2,480	3,898	5,298	4,458	3,363	3,238	3,096	3,236	3,336	3,571	3,711
Percent Reserve[b]	18.9	13.7	15.1	14.4	21.6	28.2	22.7	16.4	15.1	13.8	13.9	13.7	14.1	14.0
Excess or Deficiency[c]	734	-52	175	68	1,377	2,663	1,706	489	238	-34	-29	-69	19	7
Capacity Addition & Retirement Program[d]	C4 C5 -SL2		LAS1	LAS2	BY1 BR1	BY2 BR2			LAN2[f]	LAN1[f] FOS[g]	FOS[g] FOS[g]	FOS[g] FOS[g]	CC1[f] FOS[g] FOS[g] -RGL	CC2[f] FOS[g] -WK6

Note: Values in MW unless other wise indicated.

[a] Peak load estimates through 1987 are based on econometrics modeling. Peak load estimates beyond 1987 are based on extrapolations of econometric model results.

[b] Percent reserve is reserve margin expressed as a percent of peak load.

[c] Based on a required margin of 14 percent.

[d] Units shown added or retired are those units available or not available for the indicated year's peak load and may have actually been added or retired that year or after the peak load of the year before.

[e] See Table 1.1-29 for key to unit abbreviations; those not listed are as follows: F18 = Fisk 18; JO5 = Joliet 5; SL1 = State Line 1; WK5 = Waukegan 5; DX4 = Dixon 4; and DX5 = Dixon 5.

[f] Partially authorized.

[g] Not authorized.

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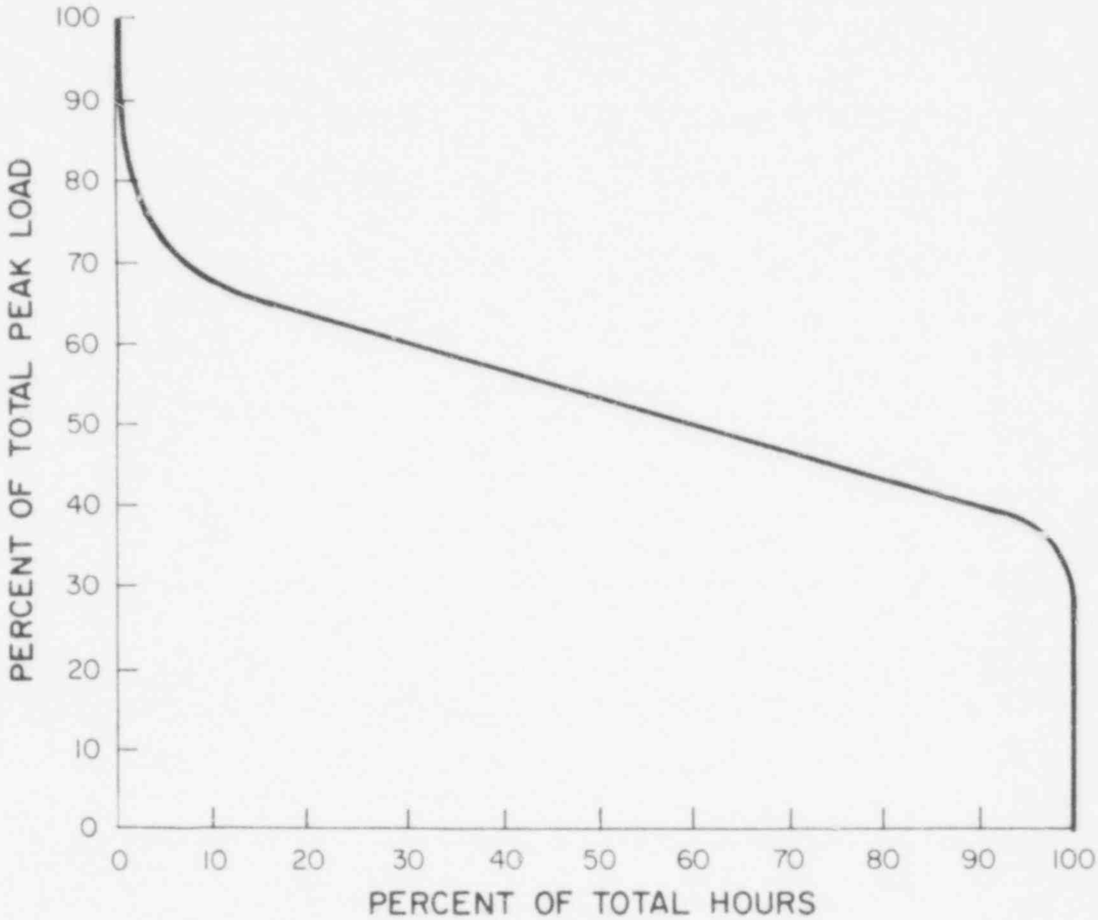

REVISION 2 8/79

CARROLL COUNTY NUCLEAR GENERATING STATION - UNITS 1 & 2

SITE SUITABILITY - ENVIRONMENTAL REPORT

FIGURE 1.1-10

LOAD DURATION CURVE FOR 1978

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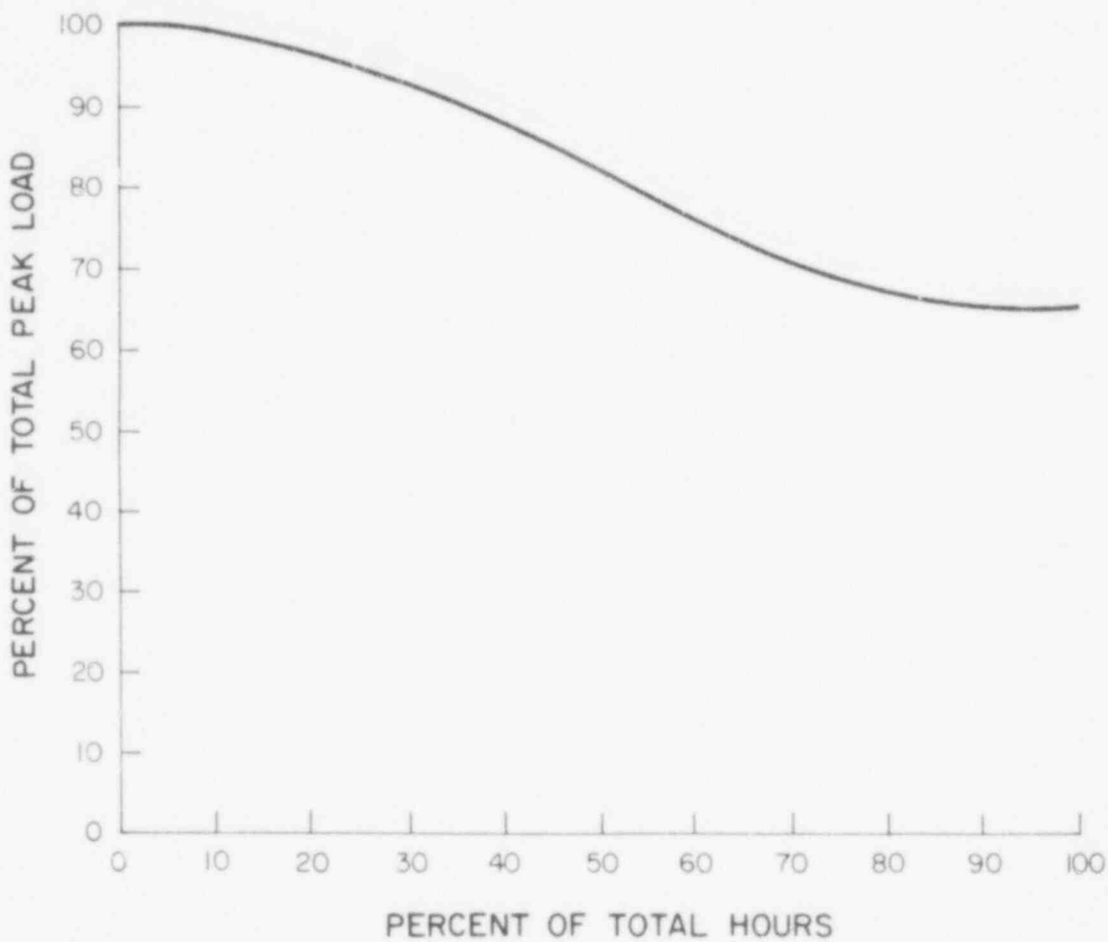

902141

REVISION 2 8/79

CARROLL COUNTY NUCLEAR GENERATING STATION - UNITS 1 & 2
SITE SUITABILITY- ENVIRONMENTAL REPORT

FIGURE 1.1-11
DAILY LOAD DURATION CURVE FOR PEAK DAY OF 1978

1.2 OTHER OBJECTIVES - COMMONWEALTH EDISON COMPANY

No objectives other than the commercial generation of electricity are being considered for the Carroll County Nuclear Generating Station - Units 1 & 2.

1.3 CONSEQUENCES OF DELAY - COMMONWEALTH EDISON COMPANY

The most important consequence of a possible delay in the operation of the Carroll County Nuclear Generating Station is that there might not be adequate generation to assure a reliable electric supply to Commonwealth Edison Company's customers. Without an adequate supply, the possibility of voltage reductions, brownouts, or service interruptions is greatly increased.

The next most important consequence of a delay in the operation of the Carroll County Nuclear Generating Station Units 1 and 2 is that the mix of units with varying sources of fuel is not optimum. The direct consequence is that cost of generation would be higher. The more costly fossil fueled units would have to be operated to supply the necessary energy to meet customers' requirements. The environmental impact of operating the older fossil-fueled units in addition to new cyclical fossil units in a base load manner rather than nuclear units would be a serious consequence of a delay. 2

1.4 SYSTEM DEMAND AND RELIABILITY - INTERSTATE POWER COMPANY

Interstate Power Company (ISP) requires additional base load capacity primarily to meet increased electric power demands and the associated reserves. Also, capacity is required to cover retirement of obsolete units which cannot be retrofitted to meet current environmental standards and to cover derating of units caused by addition of pollution control systems.

A summary of ISP's existing units is presented in Table 1.4-1 which lists the unit designation, type, fuel, and capabilities. A 150 MW share of a 650 MW coal-fired unit, Guthrie County #1 has been committed; this unit is scheduled for operation late in 1984. The Guthrie County unit 2
will be located approximately 40 miles west of Des Moines, Iowa.

In addition to the owned and committed units, ISP's load growth will require additional capacity prior to the availability of the proposed Carroll County units. The 224 MW ISP portion of Carroll County units could be fully 2
utilized to provide a portion of the generating capacity needed as early as 1987. This capacity will be acquired by one or more of the following shorter lead time methods:

a. Joint ownership of a coal-fired unit;

b. Combustion turbine additions; or

c. Purchased capacity.

ISP is a member of Mid-Continent Area Power Pool (MAPP). MAPP is a diverse group of generating utilities consisting of 1 federal system, 12 investor-owned systems, 13 municipal systems, 8 rural electric G&T cooperatives and 2 public power districts. Close liaison is also maintained with Manitoba Hydro which is interconnected with the MAPP system. While the basic concept of local individual utility control and operation of facilities has been retained, close coordination of activities is maintained through a staffed control center in Minneapolis and six active committees. The MAPP organization charts are included as Figures 1.4-1 and 1.4-2. Liaison is maintained between MAPP and the Mid-American Interpool Network (MAIN) council.

ISP is also a member of Mid-Continent Area Reliability Coordination Agreement (MARCA), one of nine reliability councils in the country.

ISP initiated an energy conservation program in 1972. A report, FPC Docket R-454, Order 495, has been submitted to the Federal Power Commission (FPC) each year since 1973. The program remains essentially unchanged except for new communications with our customers and the following changes and experiments.

ISP has promoted superior insulation for the past 17 years, ceiling R-36, walls R-14, floor R-22, and basement R-8. In 1977 these were increased to R-44, R-18, R-22, and R-8, respectively. Please see Appendix 1.4A.

ISP has six experimental installations of gas furnaces converted to electric ignition and electric stack cutoffs. No information is available on the savings at this time.

ISP has also experimented with added insulation on a water heater and hot water pipes; a copy of the report is included as Appendix 1.4B.

As to energy conservation through rate design, ISP's retail tariff changes since 1970 include the following:

a. A reduction in the number of blocks in declining block rates with a relatively higher increase in the end block of all rates;

b. Elimination of uncontrolled, separately metered water heating and planned time controlled off-peak service; and

c. Implementation of some off-peak rates for specific utilizations.

ISP has conducted a survey of all large power and lighting customers to determine the feasibility of an interruptible or off-peak industrial rate. The initial results were negative but the subject is still under study. ISP has also provided state regulatory commissions with class cost of service studies to support cost of service based rates.

ISP is participating in a price elasticity study with the Minnesota-Wisconsin Power Suppliers Group but no results are available at this time.

Both Iowa and Minnesota Public Service Commissions are engaged in rate design studies pursuant to Department of Energy (DOE) contracts, however, it is not evident at this time what changes those studies may effect. Inasmuch as ISP is a relatively high load factor system, it is not anticipated that time of day and seasonal rates would have a significant effect on system peaks as it might on the low load factor system.

At this time there is no measurable change in consumption patterns directly attributable to changes in rate design or rate level.

1.4.1 Load Characteristics

1.4.1.1 Load Analysis

The annual peak load demands for 1968 through 1978 and the forecast demands for 1979 through 1994 are in Table 1.4-2. The annual net energy requirements for 1968 through 1978 and the forecast energy requirements for 1979 through 1994 are in Table 1.4-3. The load factor with gigawatt hours (GWHR) into the system and net MW as the basis is expected to raise from the present 62.5 percent to about 64 percent in 1994. An estimated load duration curve is shown in Figure 1.4-3. The generating capability, type and fuel mix for 1978, 1984, and 1988 is shown graphically in Figure 1.4-4. 2 2

1.4.1.2 Demand Projections

The annual peak load demands and forecast demands are in Table 1.4-4 and are shown graphically in Figure 1.4-5. Demands have been estimated by using a linearized least squares curve fitting process for historical data. The trending process is done for the total load and for the load after the demands for the five large industrials have been removed. The five large industrial customers account for over 20 percent of the system demand. Demand projections for the large industrial customers are made individually after discussion with the industries involved concerning their future plans. Accuracies for the one- and two-year forecasts are very good, as indicated in Tables 1.4-4 and 1.4-5. Trends are made using several time periods to get a feel for the limits of growth indicated by appropriate time periods. The square of the regression coefficients usually exceed 0.96 indicating excellent stability in the load growth patterns. A reasonable growth rate is selected using the several trend estimates, some knowledge of the area's economy, and some knowledge of the national energy picture. This rate is expected to be 5.0 percent for the next 15 years.

ISP is fortunate to be located in an area of relatively good economic stability and high productivity. Approximately 75 percent of ISP's revenue is from Iowa customers. The Iowa unemployment rate is significantly lower than for the United States, Figure 1.4-6. The Iowa State Gross Product growth rate of 10 percent is also exceeding the GNP growth rate of 9.1 percent, Figure 1.4-7. The largest city in ISP's

service area has a population of about 65,000 avoiding many of the metropolitan area problems; there are no slums and crime rates are considerably less than the national averages.

The characteristics of the ISP system have, in our opinion, not dictated the general use of more sophisticated and expensive methods of forecasting such as using an econometric model. Stone & Webster Management Consultants, Inc. made an energy peak load forecast for the ISP system in June 1978 which considered the population characteristics, appliance saturation, and analyzed the temperature characteristics. A copy of the report is included as Appendix 1.4C.

A copy of ISP's response to FPC Order 496 is included as Appendix 1.4D.

1.4.1.3 Power Exchanges

Capacity sales and purchases for 1971 through 1994 are listed in Table 1.4-6. ISP has had a policy of owning the generation required to serve their loads and uses capacity from purchases and sales as a tuning mechanism. 2

1.4.2 System Capacity

ISP makes studies of alternate generation expansion plans with the following constraints and factors considered:

a. Forecast demands;

b. Demand distribution over system;

c. Unit size;

d. Type of unit needed (peaking, base load or intermediate);

e. Fuel type;

f. Transmission facilities available for additions required;

g. Transmission system addition deferments by adding peaking capacity;

h. Alternate source deferments by adding peaking standby capacity;

i. Transportation system available; and

j. Environmental impacts.

Economic analysis is made by minimum revenue requirements or minimum present worth methods.

MAPP pool members make studies that include all pool members and also studies that cover subgroups. ISP participates in the pool studies and in the subgroups of Minnesota-Wisconsin and Iowa. The studies include generation and transmission studies under light and heavy loading, generation mix studies including pumped storage systems, transmission bottleneck studies, regional transfer studies, reserve requirements studies and probable and extreme disturbance studies.

For planning purposes MAPP and MARCA can be considered the same since MAPP has approximately 96 percent of the MARCA load. The historical load and capability data for ISP and MARCA are presented in Table 1.4-7. The 1979 through 1988 forecast load and capability data for MARCA are in Table 1.4-8. Data for the years 1989 through 1994 are not available at this time. The 1979 through 1994 forecast load and capability data for ISP are in Table 1.4-9. The Carroll County Station Units 1 and 2 are scheduled to be in service 2
in the fall of 1990 and 1991, respectively. The deficiency in reserve margin for the summer peak in 1992 is forecasted as 375 MW with Carroll County Units 1 and 2 in service. As shown on Table 1.4-9, the deficiency in capacity continues to increase beyond 1992. Thus, there will be a need for the power produced by Carroll County Station Units 1 and 2 during the time period that the Early Site Review findings are valid.

All of ISP's existing and committed generating units are listed in Table 1.4-1.

1.4.3 Reserve Margins

1.4.3.1 Scheduling of Unit Outages

All planned maintenance is scheduled one year in advance and updated when necessary. Unit outages are scheduled to minimize system deficiencies, that is, the largest units are scheduled during the periods of low energy demand. No unit outages are scheduled during periods of peak demand.

Unit outage duration is determined by the type and amount of maintenance required. All boilers are inspected yearly. All turbines are inspected after the first year of operation and after the initial inspection every 5 years.

The unit outage schedule is reviewed by MAPP operating personnel along with the schedules of all other members to

determine if sufficient operational generating capacity is available within the MAPP organization at all times.

1.4.3.2 Reserve Requirement Methods

Installed reserve requirements are determined by action of MAPP and MARCA groups and are periodically confirmed by probablistic studies performed by the group. At the present time each Company's installed generating capacity for any month, adjusted for power purchases and sales, is required to be not less than its maximum hourly integrated demand for that month plus a reserve of 15 percent (10 percent for Hydro) of such demand for the 12 months ending with the subject month.

This percent reserve requirement is based on historical data and judgment which has, over an extended period in the past, resulted in satisfactory reliability. Studies are run periodically to confirm that continued use of the current percent reserve requirement will result in a continuing adequate reliability level. These studies use a loss of load probability (LOLP) approach and include consideration of forecast daily peak demand, generating capability additions and retirements, maintenance of equipment, and forced outage rates of units.

The program determines a maintenance schedule based on maximizing capacity margin, and calculates on a weekly basis (48 week year) the probability of load exceeding available capacity. Annual cumulative probabilities are calculated by averaging all of the weekly probability values.

Frequently, special studies are run to investigate the effect of forecast error, varying unit size and type, changes in forced outage rates due to unit maturity or additional equipment such as sulfur scrubbers, and assumed sales of surplus capacity.

The latest available Reserve Requirement Study is dated October 1977 and covers the period from 1976-1985.

1.4.3.3 Operation of the Nuclear Units and Interconnections

Capacity additions are required during the proposed years of operation. The proposed nuclear units will be operated as base load units. Cost factors and system load factors warrant base load capacity additions.

Planned interconnections for the ISP system are a 345 kV line to the Dubuque, Iowa area that will interconnect with the 345 kV system at Hazleton, Iowa and a 345 kV line to the Clinton, Iowa area. Both of these lines are in the MARCA R-362 report on file with the Federal Power Commission. The regional interchange through the ISP system exceeds the ISP system load. Interchange capabilities of the transmission system are under continual scrutiny of ISP, the MAPP Planning Committee and the MARCA Council.

1.4.3.4 Reserve Requirements

ISP carries the MAPP-MARCA reserve requirements of 15 percent.

1.4.4 External Supporting Studies

1.4.4.1 Minimum Reserves

Minimum reserve obligations for each member of the MAPP-MARCA system is 15 percent for all units except hydros which are 10 percent. These reserve requirements were reaffirmed by a study of the Reserve Requirements Task Force of MAPP for the years 1976 through 1985. The report is titled "Reserve Requirements Study 1976-1985" dated October 1977.

1.4.4.2 Area Wide Power Supply

The MAPP-MARCA load and capability data extend only through 1987. The proposed Carroll County units will help cover pool and ISP deficits that are reported as early as 1985.

1.4.4.3 Minimum Reserve Requirements 2

The reserve requirements are reviewed periodically so that the changing effects of unit size, unit type, reliability and changing technology can be considered. The latest year that has been considered is 1985.

TABLE 1.4-1

INTERSTATE POWER COMPANY EXISTING UNITS

	UNIT	YEAR INSTALLED	UNIT TYPE[a]	FUEL[b] PRI	FUEL[b] ALT	CAPACITY FACTOR	POWER PLANT CAPABILITIES KW CAPABILITY NET WINTER UNIT	NET WINTER PLANT	NET SUMMER UNIT	NET SUMMER PLANT
STEAM PLANTS										
M. L. Kapp Station	#1	1947	I	C	G	23	18,500		18,500	
(Clinton, Iowa)	#2	1967	B	C	--	46	220,000		220,000	
								238,500		238,500
Dubuque, Iowa	#2	1929	P	C	G	1	15,000		15,000	
	#3	1952	I	C	G	48	30,000		30,000	
	#4	1959	B	C	G	49	35,000		35,000	
								80,000		80,000
Fox Lake	#1	1950	P	O	G	27	12,000		12,000	
(Sherburn, Minn.)	#2	1951	P	O	G	22	12,000		12,000	
	#3	1962	B	C	O/G	33	86,000		84,000	
								110,000		108,000
Lansing, Iowa	#1	1948	I	C		35	17,500		17,500	
	#2	1949	I	C		33	10,700		10,700	
	#3	1957	I	C		40	33,800		33,800	
	#4	1977	B	C		76	260,000		260,000	
								322,000		322,000
Neal	#4	1979	B	C		80 Est.	100,000		100,000	
								100,000[d]		100,000[d]
TOTAL STEAM								850,500		848,500
DIESEL PLANTS										
Dubuque, Iowa	#1	1966	P	O		2	2,000		2,300	
	#2	1966		O		2	2,000		2,300	
								4,000		4,600
Hills, Minnesota	#2	1960	P,S	O		1	2,000		2,000	
								2,000		2,000
Lansing, Iowa	#1	1970	P	O		0	1,000		1,000	
	#2	1971	P	O		0	1,000		1,000	
								2,000		2,000
New Albin, Iowa	#1	1970	P,S	O		0	700		700	
								700		700
Rushford, Minnesota	#1	1961	P,S	O		0	2,000		2,000	
								2,000		2,000
TOTAL DIESEL								10,700		11,300
COMBUSTION TURBINES										
Montgomery	#1	1974	P,S	O		3		27,400		22,200
Fox Lake	#4	1974	P	O		4		26,100		21,300
TOTAL COMBUSTION TURBINES								53,500		43,500
COMMITTED UNITS										
Guthrie[c]	#1	1985	B	C		80 Est.	150,000[c]		150,000[c]	
Carroll County	#1	1990	B	N		65 Est.	112,000[e]		112,000[e]	
Carroll County	#2	1991	B	N		65 Est.	112,000[e]		112,000[e]	
								374,000		374,000
TOTAL SYSTEM								1,288,700		1,277,300

[a] Unit Type: B - Base Load, I - Intermediate Load, P - Peaking, S - Standby.

[b] Fuel: C - Coal, O - Oil, G - Gas, N - Nuclear.

[c] 150 MW Share OF 650 MW Unit.

[d] 100 MW Share of 576 MW Unit.

[e] 112 MW Share of 1,120 MW Unit.

Revision 1
5/79

Revision 2
8/79

902151

TABLE 1.4-2

INTERSTATE POWER COMPANY

HISTORICAL AND FORECAST DEMANDS

HISTORICAL		FORECAST	
YEAR	DEMAND (MW)	YEAR	DEMAND (MW)
1968	373	1979	753
1969	385	1980	821
1970	410	1981	858
1971	465	1982	898
1972	515	1983	939
1973	536	1984	983
1974	533	1985	1,030
1975	576	1986	1,079
1976	599	1987	1,131
1977	668	1988	1,185
1978	695	1989	1,244
		1990	1,305
		1991	1,370
		1992	1,439
		1993	1,511
		1994	1,588

2

Historical: $N = 11$, $y = y_o(1.06489)^n$, $r^2 = .974$

Forecast: $N = 16$, $y = y_o(1.049)^n$, $r^2 = 0.999$

902152

TABLE 1.4-3

INTERSTATE POWER COMPANY

HISTORICAL AND FORECAST ENERGY

HISTORICAL		FORECAST	
YEAR	NET ENERGY (GWHR)	YEAR	NET ENERGY (GWHR)
1968	1,987	1979	3,990
1969	2,171	1980	4,259
1970	2,265	1981	4,489
1971	2,409	1982	4,731
1972	2,548	1983	4,986
1973	2,637	1984	5,256
1974	2,758	1985	5,540
1975	2,883	1986	5,840
1976	3,113	1987	6,157
1977	3,348	1988	6,491
1978	3,624	1989	6,842
		1990	7,211
		1991	7,600
		1992	8,011
		1993	8,443
		1994	8,899

Historical: $N = 11$, $y = y_o(1.05731)^n$, $r^2 = 0.990$

Forecast: $N = 16$, $y = y_o(1.0544)^n$, $r^2 = 0.9998$

2

TABLE 1.4-4

INTERSTATE POWER COMPANY NET ENERGY AND DEMAND: FORECAST VERSUS ACTUAL

YEAR			JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.
1972	Demand (MW)	Forecast	442	442	431	425	445	457	501	501	470	455	455	464
		Actual	403	394	389	374	427	442	499	515	443	435	450	456
	Energy (GWH)	Forecast	Not Available											
		Actual	220	211	217	197	196	201	210	217	226	206	222	225
1973	Demand (MW)	Forecast	456	456	445	425	440	490	543	543	490	465	460	476
		Actual	429	427	428	411	386	482	494	536	431	411	447	426
	Energy (GWH)	Forecast	252	226	227	222	232	234	253	250	233	231	238	247
		Actual	237	223	213	209	201	205	226	235	2,281	216	219	225
1974	Demand (MW)	Forecast	456	456	437	415	435	496	551	551	496	463	471	482
		Actual	429	424	433	411	417	481	533	505	441	430	454	462
	Energy (GWH)	Forecast	257	224	222	219	225	227	254	263	242	237	241	263
		Actual	236	225	218	220	231	224	243	245	236	220	221	239
1975	Demand (MW)	Forecast	475	473	473	450	462	543	560	578	517	479	511	512
		Actual	472	465	452	440	489	567	576	570	511	454	465	499
	Energy (GWH)	Forecast	260	235	240	225	234	243	267	268	249	251	245	261
		Actual	248	243	239	224	216	227	250	259	258	227	237	255
1976	Demand (MW)	Forecast	502	501	501	476	492	579	596	616	551	511	535	536
		Actual	494	496	482	446	445	533	599	568	547	492	506	534
	Energy (GWH)	Forecast	279	254	267	246	252	262	297	304	264	261	265	284
		Actual	265	264	256	243	231	242	265	287	278	245	267	270
1977	Demand (MW)	Forecast	526	524	524	498	527	569	640	608	584	526	547	573
		Actual	541	503	480	478	551	637	668	569	512	507	550	575
	Energy (GWH)	Forecast	305	283	285	263	282	287	328	333	302	296	288	304
		Actual	286	289	265	253	260	273	287	316	281	262	286	290
1978	Demand (MW)	Forecast	571	573	557	527	510	611	684	652	626	564	585	613
		Actual	599	555	524	484	570	656	650	690	695	564	587	587
	Energy (GWH)	Forecast	327	303	300	277	304	313	356	346	309	323	311	329
		Actual	368	298	223	276	277	285	321	319	332	306	303	317

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POOR ORIGINAL

TABLE 1.4-5

DEMAND FORECAST ACCURACIES BY YEAR OF FORECAST

A C T U A L

	1971	Dev. from Actual		1972	Dev. from Actual		1973	Dev. from Actual	
	MW	MW	%	MW	MW	%	MW	MW	%
1971	469	4	0.86	465					
1972	507	-14	-2.72	501	-14	-2.72	515		
1973	531	-5	-0.93	531	-5	-0.93	543	7	1.31
1974	562	29	5.44	562	29	5.44	575	42	7.88
1975	597	21	3.65	597	21	3.65	611	35	6.08
1976	635	38	6.01	635	36	6.01	653	58	9.52
1977	673	5	0.75	673	5	0.75	694	26	3.89
1978	715	20	2.88	715	20	2.88	737	42	6.04
1979	759			759			783		
1980	827			827			832		
1981				898			895		
1982							942		

	1974	Dev. from Actual		1975	Dev. from Actual		1976	Dev. from Actual	
	MW	MW	%	MW	MW	%	MW	MW	%
1973	536								
1974	551	18	3.38	533					
1975	590	14	2.43	578	2	0.35	576		
1976	638	39	6.51	616	11	2.04	616	17	2.84
1977	677	9	1.35	660	-8	-1.20	660	-8	-1.20
1978	718	23	3.31	694	-1	-0.14	694	-1	-0.14
1979	762			731			734		
1980	810			770			770		
1981	867			813			813		
1982	916			856			856		
1983	975			902			902		
1984	1,038			952			952		
1985	1,103			1,005			1,005		

	1977	Dev. from Actual		1978	Dev. from Actual		1979	Dev. from Actual	
	MW	MW	%	MW	MW	%	MW	MW	%
1976	595								
1977	640	-28	-4.19	668					
1978	692	-3	-0.43	684	-11	-1.61	695		
1979	741			736			753		
1980	776			771			821		
1981	816			818			858		
1982	854			847			898		
1983	896			889			939		
1984	943			933			983		
1985	969			963			1,030		
1986	1,016			1,030			1,079		
1987				1,083			1,131		
1988				1,139			1,185		
1989				1,156			1,245		
1990							1,305		
1991							1,370		
1992							1,439		

Highest Forecast Over Peak 58 MW = 9.52%
Lowest Forecast Under Peak 28 MW = 4.19%
Mean Error = 2.20%
Standard Deviation = 3.22%
N = 25

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TABLE 1.4-6

SEASONAL CAPACITY TRANSACTIONS

		PARTICIPATION	FIRM			PARTICIPATION	FIRM
1971	Purchases	35	0	1983	Purchases	0	3
	Sales	0	56		Sales	0	0
1972	Purchases	33	0	1984	Purchases	0	3
	Sales	0	7		Sales	0	0
1973	Purchases	49	0	1985	Purchases	0	3
	Sales	0	0		Sales	0	0
1974	Purchases	65	2	1986	Purchases	0	3
	Sales	0	0		Sales	0	0
1975	Purchases	68	21	1987	Purchases	0	3
	Sales	0	0		Sales	0	0
1976	Purchases	121	0	1988	Purchases	0	3
	Sales	0	0		Sales	0	0
1977	Purchases	0	0	1989	Purchases	0	3
	Sales	27	3		Sales	0	0
1978	Purchases	0	4	1990	Purchases	0	3
	Sales	30	0		Sales	0	0
1979	Purchases	0	0	1991	Purchases	0	3
	Sales	26	7		Sales	0	0
1980	Purchases	0	0	1992	Purchases	0	3
	Sales	0	0		Sales	0	0
1981	Purchases	0	3	1993	Purchases	0	3
	Sales	0	0		Sales	0	0
1982	Purchases	0	3				
	Sales	0	0				

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Note: Values in MW.

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TABLE 1.4-7

LOAD AND CAPABILITY DATA 1973-1978

INTERSTATE POWER COMPANY AND MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)

	1973		1974		1975		1976		1977		1978	
	ISP	MARCA	ISP	MARCA	ISP	MARCA	ISP	MARCA	ISP	MARCA	ISP	MARCA
Demand	536	13,959	533	13,706	576	14,503	599	14,938	668	16,586	695	17,596
Purchase and Sales	49	--	67	--	89	--	121	--	(30)	--	(30)	--
General Capacity	551	15,855	594	16,991	587	18,464	587	19,920	847	21,062	826	22,268
Capacity Obligation (Includes 15 Percent Reserve)	616	--	613	--	662	--	689	--	768	--	799	--
Surplus	(16)	--	48	--	14	--	19	--	49	--	(3)	--
Margin Percent	11.9	13.6	24.0	24.0	17.4	27.3	18.2	33.4	22.3	27.0	14.5	26.6

Note: Values in MW.

TABLE 1.4-8

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (INCLUDING OTP) ESTIMATED LOAD AND GENERATING CAPABILITY DATA, 1979-1988

	1979		1980		1981		1982		1983	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. Seasonal System Demand	19,470	17,821	20,824	18,926	21,928	20,104	23,140	21,227	24,361	22,450
2. Annual System Demand	19,983	20,469	21,302	21,710	22,478	22,916	23,719	24,140	24,962	25,436
3. Firm Purchases - Total	1,191	1,230	1,794	1,038	1,693	1,022	1,686	987	1,682	986
4. Firm Sales - Total	1,559	1,604	1,293	1,388	1,199	1,425	1,115	1,299	1,132	1,316
5. Seasonal Adjusted Net Demand	19,838	18,195	20,323	19,276	21,434	20,507	22,569	21,539	23,811	22,780
6. Annual Adjusted Net Demand	20,351	20,843	20,801	22,060	21,984	23,319	23,148	24,452	24,412	25,766
7. Net Generating Capability[a]	24,527	25,770	25,311	27,212	27,742	28,567	28,175	29,258	28,733	29,938
8. Participation Purchases - Total	1,690	1,472	1,716	1,483	1,369	1,254	1,297	1,2424	1,3857	1,307
9. Participation Sales - Total	1,664	1,459	1,737	1,395	1,281	1,2163	1,260	1,205	1,282	1,272
10. Adjusted Net Capability	24,553	25,783	25,290	27,300	27,830	28,605	28,212	29,295	28,836	29,973
11. Net Reserve Capacity Obligation[b] (6x15 percent)	2,954	3,029	3,019	3,208	3,196	3,398	3,368	3,567	3,561	3,766
12. Total Firm Capacity Obligation	22,792	21,224	23,342	22,484	24,630	23,905	25,937	25,106	27,372	26,546
13. Surplus or Deficit (-) Capacity	1,761	4,559	1,948	4,816	3,200	4,700	2,275	4,189	1,464	3,427

Notes: Values in MW.

Prepared by Mid-Continent Area Reliability Coordination Agreement (MARCA).

Date prepared: January 1, 1979.

Summer: May 1 - October 31; Winter: November 1 - April 30.

[a]Derived from existing capability and committed future capability changes.

[b]10 percent for a predominantly hydro system.

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TABLE 1.4-8 (continued)

	1984 SUMMER	1984 WINTER	1985 SUMMER	1985 WINTER	1986 SUMMER	1986 WINTER	1987 SUMMER	1987 WINTER	1988 SUMMER	1988 WINTER
1. Seasonal System Demand	25,657	23,776	27,0[illegible]6	25,072	28,392	26,426	29,736	27,819	31,147	29,237
2. Annual System Demand	26,274	26,830	27,70[illegible]	28,235	29,074	29,674	30,500	31,140	31,972	32,609
3. Firm Purchases - Total	1,679	985	1,677	986	1,676	989	1,670	984	1,658	974
4. Firm Sales - Total	1,149	1,329	1,164	1,340	1,175	1,456	1,186	1,464	1,194	1,471
5. Seasonal Adjusted Net Demand	25,127	24,120	26,553	25,426	27,891	26,893	29,252	28,299	30,683	29,734
6. Annual Adjusted Net Demand	25,744	27,174	27,194	28,589	28,573	30,141	30,016	31,620	31,508	33,106
7. Net Generating Capability[a]	29,920	30,553	29,747	30,559	31,446	32,257	31,444	32,226	31,378	32,545
8. Participation Purchases - Total	1,047	1,197	1,037	1,187	1,227	1,277	1,102	1,102	1,082	1,082
9. Participation Sales - Total	1,014	1,164	1,005	1,155	1,097	1,147	967	1,067	1,032	1,032
10. Adjusted Net Capability	29,953	30,586	29,779	30,591	31,576	32,387	31,579	32,261	31,428	32,595
11. Net Reserve Capacity Obligation (6x15 percent)[b]	3,760	3,975	3,977	4,188	4,182	4,419	4,397	4,642	4,623	4,864
12. Total Firm Capacity Obligation	28,887	28,095	30,530	29,614	32,073	31,312	33,649	32,941	35,306	34,598
13. Surplus or Deficit (-) Capacity	1,066	2,491	-751	97[illegible]	-497	1,075	-2,070	-680	-3,878	-2,003

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INTERSTATE POWER COMPANY

ESTIMATED LOAD AND GENERATING CAPABILITY DATA, 1979-1994 2

	1979		1980		1981		1982		1983	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. Seasonal System Demand	753	666	821	708	858	734	898	762	939	791
2. Annual System Demand	753	753	821	821	858	858	898	898	939	939
3. Firm Purchases - Total	--	--	--	--	--	--	--	--	--	--
4. Firm Sales - Total	6	--	--	--	--	--	--	--	--	--
5. Seasonal Adjusted Net Demand	759	666	821	708	858	734	898	762	939	791
6. Adjusted Net Demand	759	753	821	821	858	858	898	898	939	939
7. Net Generating Capability[a]	903	910	903	910	903	910	903	910	903	910
8. Participation Purchases - Total	--	--	3	3	3	3	3	3	3	3
9. Participation Sales - Total	26	--	--	--	--	--	--	--	--	--
10. Adjusted Net Capability	877	910	906	913	906	913	906	913	906	913
11. Net Reserve Capacity Obligation (6 x 15 percent)[b]	114	114	123	123	129	129	135	135	141	141
12. Total Firm Capacity Obligation	873	780	944	831	987	863	1,033	897	1,080	932
13. Surplus or (Deficit) Capacity	4	130	(38)	82	(81)	50	(127)	16	(174)	(19)

Notes: Values in MW.

Prepared for Mid-Continent Area Power Pool (MAPP).

Date prepared: January 1, 1979.

Summer: May 1 - October 31; Winter: November 1 - April 30.

[a]Derived from existing capability and committed future capability changes.

[b]10 percent for a predominantly hydro system (6 x 10 percent).

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TABLE 1.4-9 (continued)

	1984		1985		1986		1987		1988		1989	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. Seasonal System Demand	983	822	1,030	854	1,079	888	1,131	923	1,185	960	1,244	999
2. Annual System Demand	983	983	1,030	1,030	1,079	1,079	1,131	1,131	1,185	1,185	1,244	1,244
3. Firm Purchases - Total	--	--	--	--	--	--	--	--	--	--	--	--
4. Firm Sales - Total	--	--	--	--	--	--	--	--	--	--	--	--
5. Seasonal Adjusted Net Demand	983	822	1,030	854	1,079	888	1,131	923	1,185	960	1,244	999
6. Adjusted Net Demand	983	983	1,030	1,030	1,079	1,079	1,131	1,131	1,185	1,185	1,244	1,244
7. Net Generating Capability[a]	903	910	1,053	1,060	1,053	1,060	1,053	1,060	1,053	1,060	1,053	1,060
8. Participation Purchases - Total	3	3	3	3	3	3	3	3	3	3	3	3
9. Participation Sales - Total	--	--	--	--	--	--	--	--	--	--	--	--
10. Adjusted Net Capability	906	913	1,056	1,063	1,056	1,063	1,056	1,063	1,056	1,063	1,056	1,063
11. Net Reserve Capacity Obligation (6 x 15 percent)[b]	147	147	155	155	162	162	170	170	178	178	187	187
12. Total Firm Capacity Obligation	1,130	969	1,185	1,009	1,241	1,050	1,301	1,093	1,363	1,138	1,431	1,186
13. Surplus or (Deficit) Capacity	(224)	(56)	(129)	54	(185)	13	(245)	(30)	(307)	(75)	(375)	(123)

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TABLE 1.4-9 (continued)

	1990		1991		1992		1993		1994	
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
1. Seasonal System Demand	1,305	1,040	1,370	1,079	1,439	1,122	1,511	1,167	1,588	1,213
2. Annual System Demand	1,305	1,305	1,370	1,370	1,439	1,439	1,511	1,511	1,588	1,588
3. Firm Purchases - Total	--	--	--	--	--	--	--	--	--	--
4. Firm Sales - Total	--	--	--	--	--	--	--	--	--	--
5. Seasonal Adjusted Net Demand	1,305	1,040	1,370	1,079	1,439	1,122	1,511	1,167	1,588	1,213
6. Adjusted Net Demand	1,305	1,305	1,370	1,370	1,439	1,439	1,511	1,511	1,588	1,588
7. Net Generating Capability[a]	1,053	1,172	1,165	1,284	1,277	1,284	1,277	1,284	1,277	1,284
8. Participation Purchases - Total	3	3	3	3	3	3	3	3	3	3
9. Participation Sales - Total	--	--	--	--	--	--	--	--	--	--
10. Adjusted Net Capability	1,056	1,175	1,168	1,287	1,280	1,287	1,280	1,287	1,280	1,287
11. Net Reserve Capacity Obligation (6 x 15 percent)[b]	196	196	206	206	216	216	227	227	238	238
12. Total Firm Capacity Obligation	1,501	1,236	1,576	1,285	1,655	1,338	1,738	1,394	1,826	1,451
13. Surplus or (Deficit) Capacity	(445)	(61)	(408)	2	(375)	(51)	(458)	(107)	(545)	(164)

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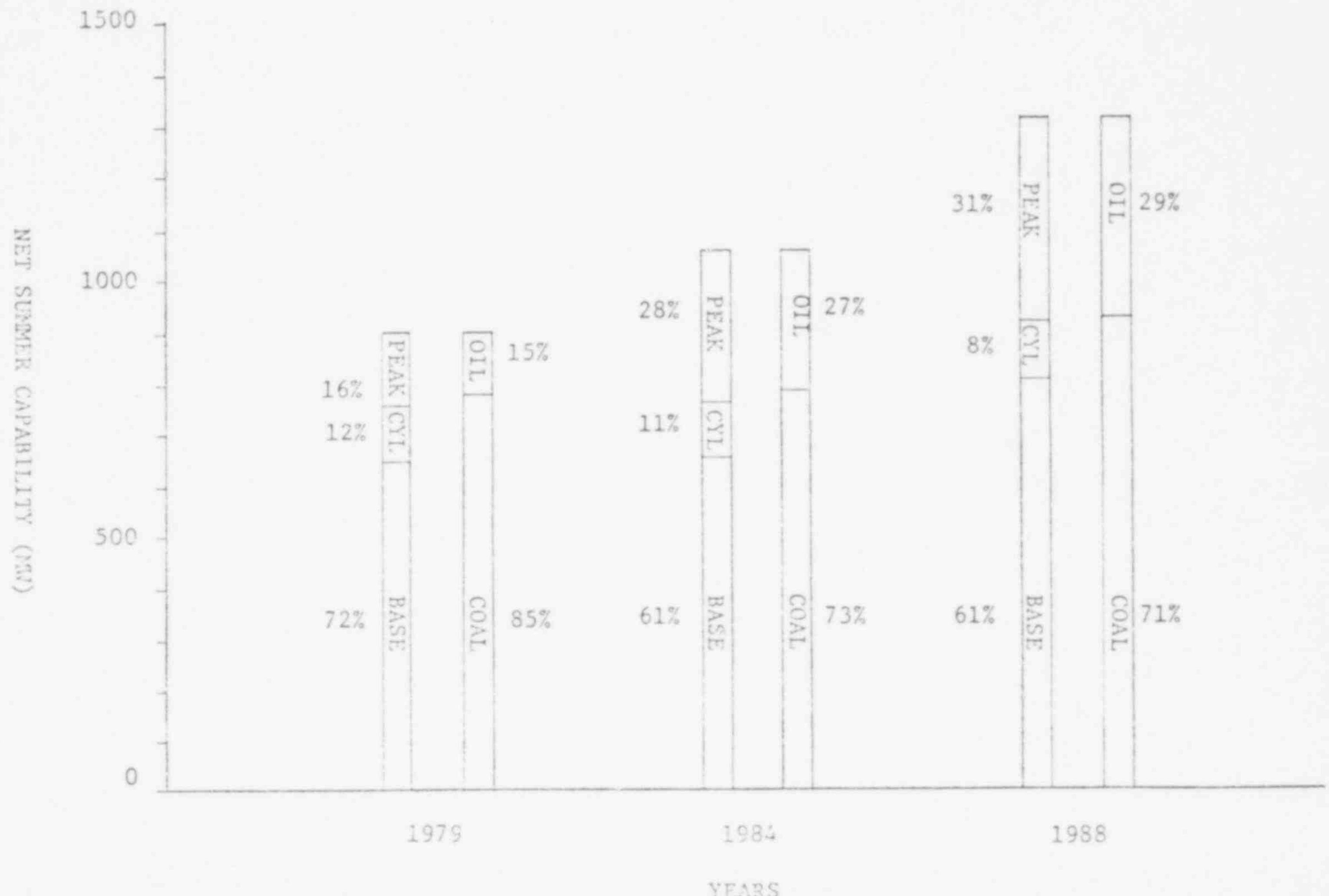


REVISION 2 8/79

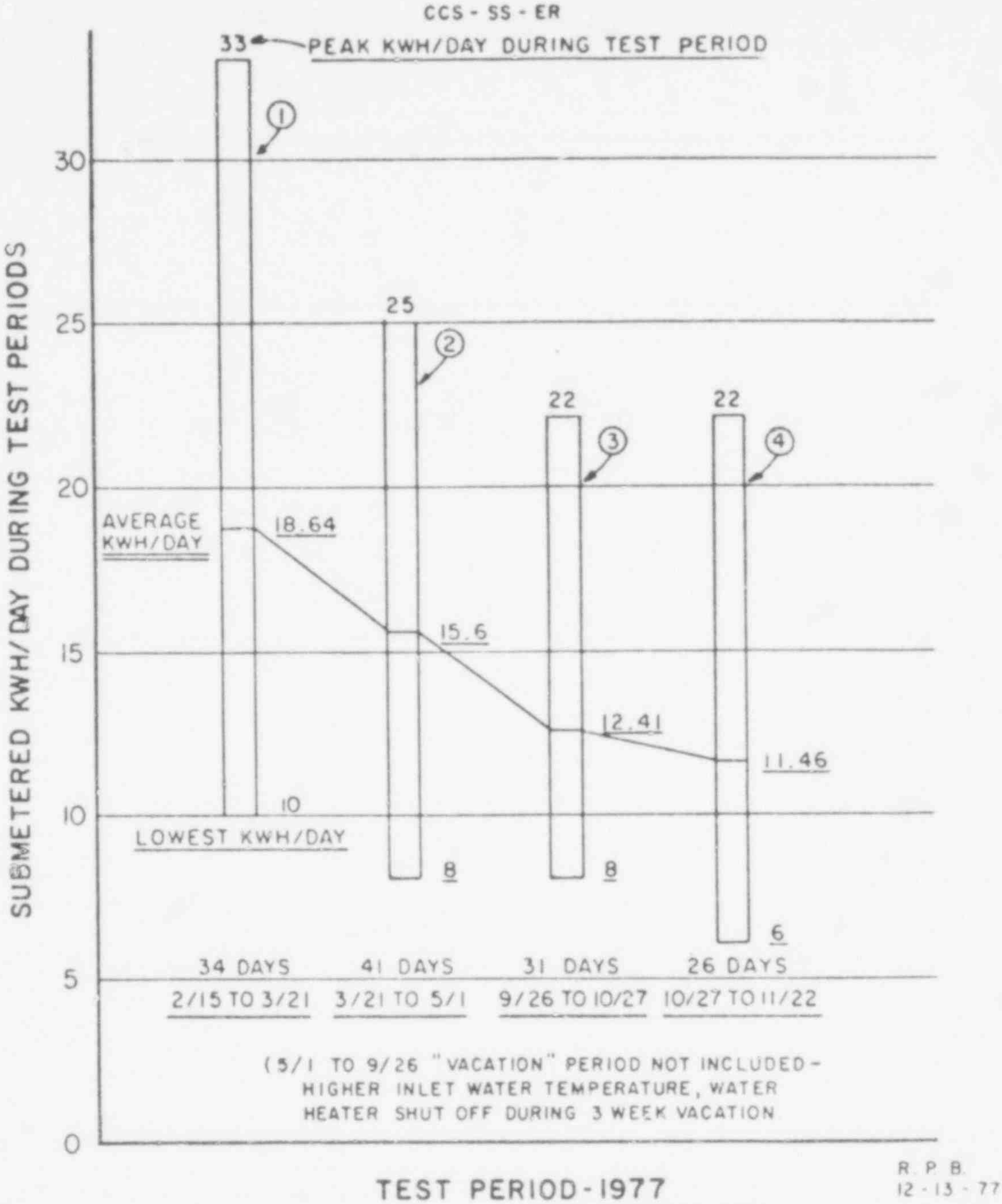
CARROLL COUNTY NUCLEAR GENERATING STATION - UNITS 1 & 2

SITE SUITABILITY - ENVIRONMENTAL REPORT

FIGURE 14.4

INTERSTATE POWER COMPANY GENERATING CAPABILITY TYPE AND FUEL MIX

302163



(1) THERMOSTAT SET AT 140° WITH NORMAL WATER HEATER INSTALLATION.

(2) WATER HEATER RAISED 4" & INSULATED. 2" JOHNS MANSVILLE INSULATION JACKET INSTALLED - 24" COLD & HOT WATER RISERS AND 8 FEET OF HORIZONTAL PIPING INSULATED - THERMOSTAT SET TO 130°.

(3) ADDITIONAL 16' OF PIPING INSULATED.

(4) THERMOSTAT SET AT 120°.

ESTIMATED SAVINGS PER YEAR	
KILOWATT-HOURS	2580
DOLLARS	$ 82.56
%	38.5

COST OF INSULATION $ 25.00

MR. & MRS. STEVE CHANDLER HOME
WATER HEATER ENERGY REDUCTION
AT FULDA, MINNESOTA
2/15 TO 11/22, 1977
52 GALLON "STATE" WATER HEATER
2 - 4500 WATT ELEMENTS
ADULTS 2 CHILDREN 3

1.7 SYSTEM DEMAND AND RELIABILITY - IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

The need for the Carroll County units is based upon projections of peak demand growth developed by Iowa-Illinois Gas and Electric Company (IIG&E). To verify and extend these projections, forecasts of demand growth have also been developed for IIG&E by a consultant. Both sets of forecasts are presented in Tables 1.7-1 and 1.7-2.

Iowa-Illinois Gas and Electric Company is an investor-owned utility providing electrical service to areas in Rock Island County, Illinois, and Scott, Johnson, and Webster counties in Iowa. The service area of IIG&E is shown in Figure 1.7-1.

1.7.1 Load Characteristics

1.7.1.1 Load Analysis

In the last decade IIG&E has experienced an average growth in annual peak demands of 6.79 percent per year. This means that the annual peak demands were doubling at least every 11 years. The number of new customers added by IIG&E each year increased at the relatively slow rate of 0.96 percent per year from 1967 to 1977. This difference between the growth rates of peak demands and the number of customers indicates that increased use by existing customers cause a major portion of the increased demand for electricity during peak periods. It is expected that the number of customers and peak demand for electricity will continue to increase during the next 10 to 20 years. Because of this expected increased demand for electricity, IIG&E is currently adding generating capacity. Plans have been made and construction started on generating units which will provide sufficient generating capacity through the early 1980's. In 1985 and thereafter, the demand projections show a need for additional generation.

Generation capacity must also be added to allow for the retirement of older units. These units are inefficient, costly to operate and maintain, and do not permit the economic and effective control of air emissions. Even if these older units scheduled to be retired between now and 1991 were retained, their generating capacity would satisfy less than 6 percent of the projected growth in demand from 1977 to 1990. |2

Additional capacity needs to be added to meet anticipated load growth and to allow for the retirement of older

generating units. The 330 MW IIG&E portion of Carroll County units could be fully utilized to provide a portion of the generating capacity needed as early as 1987. 2

The energy conservation programs of IIG&E are outlined in Appendix 1.7A.

The accredited generating capability goes below the forecast load plus 15 percent reserve required by Mid-America Power Pool (MAPP) for the summer peak of 1985 with a deficit of 129 MW, as shown in Table 1.7-11, and remains below margin requirements through 1995 (as far as forecasting has been done). The Carroll County Station Units 1 and 2 are scheduled to be in service in the fall of 1990 and 1991, respectively. The deficiency in reserve margin for the summer peak in 1992 is forecasted as 796 MW with Carroll County Units 1 and 2 in service. As shown on Table 1.7-11, the deficiency in capacity continues to increase beyond 1992. Thus, there will be a need for the power produced by Carroll County Station Units 1 and 2 during the time period that the Early Site Review findings are valid. 2

1.7.1.2 Load Characteristics

A tabulation of the IIG&E annual peak demands and annual sales for 1969 through 1978 is shown on Table 1.7-3. A monthly summary for 1978 is shown on Table 1.7-4. 2

1.7.1.3 Load Forecasts

The forecast of peak demand for IIG&E was made using the forecasting methodologies given in Appendix 1.7B. The forecasting methodology of a consultant used to verify IIG&E's methodology is described in Appendix 1.7C.

Table 1.7-5 lists forecasts of peak demand made since 1968 using the IIG&E forecast methodology. These forecasts have been compared with actual system loads for 1969 through 1978, Table 1.7-6, and reconstructued peak loads for 1969 through 1978, Table 1.7-7. Reconstructed peak loads are actual system loads adjusted for temperature variations and industrial vacations. 2

Monthly peak loads and sales for each month from October 1972 through May 1979 are compared with forecast values in Table 1.7-8. The estimates were made at year end for the following year. 2

Through 1995 the overall rate of growth of summer peak loads is forecasted to be about 6.4 percent for IIG&E. The growth rate is an indication of the type of service area and types of customers served. Each utility serves a different 2

mix of residential, commercial, and industrial customers. A higher rate of growth in a particular customer class as compared to other classes will, therefore, affect some utilities more than others.

The availability of alternate fuels will also affect the future demand for electricity. In areas where the supply of natural gas is restricted, commercial and industrial customers will turn to electricity for space heating and processing heat.

IIG&E expects to have sufficient natural gas to meet the heating needs of its customers in the foreseeable future. Although the growth rate of winter peaks will be higher than the summer peak growth rate, IIG&E is expected to remain a summer peaking company. 2

1.7.1.4 Power Supply

Table 1.7-9 lists current generating units along with information on rating, fuel type, and in-service and retirement dates. Table 1.7-10 lists the planned, net summer capabilities of additions and retirements to IIG&E generation through 1995. The net summer capability of IIG&E through 1995 is shown in Table 1.7-11. Summer capabilities of units in-service from 1974 through 1979 are listed in Table 1.7-12. This table also lists estimated capacity factors of these units for 1979 and 1991. 2

1.7.1.5 Mid-Continent Area Power Pool

IIG&E is a member of the Mid-Continent Area Power Pool (MAPP). One of the objectives of the MAPP is to coordinate the installation and operation of generating and transmission facilities. Although each member has the responsibility to provide facilities to meet its own electric requirement, participation in MAPP does allow, through the coordination of generation and transmission additions, each utility to install facilities which take advantage of economics of scale. Utilities may find that it is economical to purchase from other MAPP members to satisfy short-term deficiencies and capacity in excess of current requirements may be sold to other members of MAPP.

In order to retain a high degree of reliability in the bulk power system of MAPP, each member must have adequate accredited capability to supply their monthly peak load plus a 15 percent reserve. Even though some capability may be exchanged between members to satisfy the requirement for reserve capacity, overall Pool capability should remain at or above the level of expected loads plus 15 percent or system reliability will decrease. The summer peak loads,

capabilities, and percent margin of capability of the Mid-Continent Area Reliability Coordination Agreement (MARCA) which is approximately coincident with MAPP, are shown in Table 1.7-14.

1.7.1.6 Load Curves

Figures 1.7-2 and 1.7-3, and Table 1.7-13 show the load duration curves for 1972 through 1976 and forecast load duration curves for IIG&E. As shown, the load and required capacity vary considerably each year. Typically, peak loads are those loads occurring less than 500 hours per year (5.7 percent of annual hours). Intermediate loads are those loads occurring less than 4,000 hours per year (45.7 percent of annual hours) and base loads are loads occurring most of the year. Each type of load must be met by a specific type of generation which is most economical in terms of investment and fuel cost for that application.

It is estimated that the future load duration curve of IIG&E will be similar to the historical curves except that because of expected increases in load factor (ratio or average demand to peak demand) the curves may be shifted upward.

TABLE 1.7-1

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

FORECAST OF PEAK SUMMER DEMANDS

YEAR	PEAK LOAD (MW)
1979	1,047
1980	1,123
1981	1,205
1982	1,287
1983	1,373
1984	1,465
1985	1,564
1986	1,659
1987	1,760
1988	1,867
1989	1,981
1990	2,102
1991	2,230
1992	2,366
1993	2,510
1994	2,663
1995	2,825

2

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TABLE 1.7-2

STATISTICAL FORECAST OF ANNUAL PEAK DEMAND

FOR IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

YEAR	FORECAST	50 PERCENT CONFIDENCE LIMITS LOWER	UPPER
1977	888	845	912
1978	947	900	979
1979	1,006	956	1,036
1980	1,072	1,013	1,110
1981	1,138	1,071	1,180
1982	1,211	1,135	1,255
1983	1,290	1,215	1,340
1984	1,372	1,273	1,428
1985	1,456	1,361	1,512
1986	1,550	1,446	1,615
1987	1,650	1,541	1,719
1988	1,757	1,633	1,836
1989	1,862	1,724	1,945
1990	1,980	1,830	2,079
1991	2,100	1,938	2,193
1992	2,235	2,060	2,339
1993	2,388	2,192	2,504
1994	2,530	2,329	2,653
1995	2,686	2,461	2,815
1996	2,858	2,619	2,993
1997	3,037	2,787	3,192
1998	3,230	2,951	3,386
1999	3,427	3,123	3,604
2000	3,637	3,328	3,841
2001	3,867	3,514	4,094
2002	4,110	3,717	4,350
2003	4,392	4,011	4,624
2004	4,658	4,203	4,940
2005	4,937	4,478	5,226
2006	5,226	4,711	5,538
2007	5,577	4,987	5,933
2008	5,916	5,315	6,277
2009	6,272	5,613	6,666
2010	6,670	6,000	7,117
2011	7,124	6,409	7,559
2012	7,550	6,734	8,045
2013	8,023	7,184	8,529

Note: All figures in megawatts.

TABLE 1.7-3

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

ANNUAL PEAK DEMANDS AND

ANNUAL SALES OF ENERGY 1969-1978 2

YEAR	ANNUAL PEAK (KW)	ANNUAL SALES (MWH)
1978	883,378	3,898,069
1977	872,040	3,675,578
1976	810,670	3,439,109
1975	767,588	3,233,069
1974	745,791	3,197,978
1973	768,102	3,170,336
1972	702,362	2,939,411
1971	620,421	2,665,655
1970	616,065	2,535,426
1969	526,473	2,396,469

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TABLE 1.7-4

MONTHLY SUMMARY FOR 1978 2

MONTH	MAXIMUM LOAD (MW)	MINIMUM LOAD (MW)	MEAN LOAD (MW)	LOAD FACTOR	ENERGY (GWH)	MONTHLY MAXIMUM LOAD AS PERCENTAGE OF YEAR'S MAXIMUM
Jan.	629	262	445	0.731	342	71.2
Feb.	615	313	464	0.765	316	69.6
Mar.	590	276	443	0.752	330	66.8
Apr.	563	242	392	0.735	298	63.8
May	766	262	435	0.570	325	86.7
June	826	266	524	0.615	366	93.5
July	828	278	515	0.623	384	93.8
Aug.	848	268	532	0.636	401	96.0
Sept.	883	270	515	0.593	377	100.0
Oct.	594	276	446	0.765	338	67.3
Nov.	625	271	441	0.740	333	70.5
Dec.	639	260	450	0.730	347	72.4
Year	883	242	470	0.537	4,157	---

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TABLE 1.7-5

ANNUAL PEAK LOAD FORECASTS 1968-1990

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

DATE OF FORECAST	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
3-27-68	528	570	612	660	711	765	824	887	956	1,029				
3-17-69		572	617	665	714	767	825	883	948	1,018	1,093			
3-25-70			617	665	714	767	825	883	948	1,018	1,093	1,173		
2-10-71				665	714	767	825	883	948	1,018	1,093	1,173	1,257	
1-1-72					678	729	784	839	900	967	1,038	1,114	1,194	1,280
12-28-72						730	786	841	903	970	1,040	1,116	1,196	1,274
10-25-73							786	841	903	970	1,040	1,116	1,196	1,274
10-2-74								841	903	970	1,040	1,116	1,196	1,274
1-15-75								838	893	952	1,015	1,082	1,153	1,229
1-21-76									893	952	1,015	1,082	1,153	1,229
1-3-77										933	1,000	1,071	1,147	1,229
1-16-78											976	1,047	1,123	1,205
1-19-79												1,047	1,123	1,205

Note: Values in megawatts unless otherwise indicated.

TABLE 1.7-5 (Cont'd)

DATE OF FORECAST	1982	1983	1984	1985	1986	1987	1988	1989	1990
3-27-68									
3-17-69									
3-25-70									
2-10-71									
1-1-72									
12-28-72	1,357								
10-25-73	1,357	1,445	1,539						
10-2-74	1,357	1,445	1,539	1,639					
1-15-75	1,311	1,397	1,489	1,588	1,683				
1-21-76	1,311	1,397	1,489	1,588	1,683	1,784			
1-3-77	1,311	1,397	1,489	1,588	1,683	1,784	1,891		
1-16-78	1,287	1,373	1,465	1,564	1,659	1,760	1,867	1,980	
1-19-79	1,287	1,373	1,465	1,564	1,659	1,760	1,867	1,980	2,102

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TABLE 1.7-6

SUMMER LOAD FORECASTS AS PERCENTAGES OF ACTUAL PEAK LOADS

1969 - 1978

DATE OF FORECAST	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
03-17-69	108.7	100.2	107.3	101.7	99.9	110.6	115.0	116.9	116.7	123.8
03-25-70		100.2	107.3	101.7	99.9	110.6	115.0	116.9	116.7	123.8
02-10-71			107.3	101.7	99.9	110.6	115.0	116.9	116.7	123.8
01-01-72				96.6	94.9	105.1	109.2	111.0	110.9	117.6
12-28-72					95.1	105.4	109.5	111.3	111.2	117.8
10-25-73						105.4	109.5	111.3	111.2	117.8
10-02-74							109.5	111.3	111.2	117.8
01-15-75							109.1	110.1	109.2	115.8
01-21-76								110.1	109.2	115.9
01-03-77									107.0	113.3
01-16-78										110.5
Summer Peak Loads (Actual)	526	616	620	702	768	746	768	811	872	883

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TABLE 1.7-7

SUMMER LOAD FORECASTS

AS PERCENTAGES OF RECONSTRUCTED PEAK LOADS

1969 - 1978

DATE OF FORECAST	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
03-17-69	96.3	111.0	103.1	102.4	98.8	106.9	97.9	110.9	119.1	117.6
03-25-70		111.0	103.1	102.4	98.8	106.9	97.9	110.9	119.1	117.6
02-10-71			103.1	102.4	98.8	106.9	97.9	110.9	119.1	117.6
01-01-72				97.3	93.9	101.6	93.0	105.3	113.1	106.1
12-28-72					94.1	101.8	93.2	105.6	113.5	106.3
10-25-73						101.8	93.2	105.6	113.5	106.3
10-02-74							93.2	105.6	113.5	106.3
01-15-75							92.9	104.4	111.3	103.8
01-21-76								104.4	111.3	103.8
01-03-77									109.1	102.2
01-16-78										99.8
Reconstructed Summer Peak Load	594	556	645	697	776	772	902	855	855	978

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TABLE 1.7-8 Page 1 of 3

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

ACTUAL MONTHLY PEAK LOADS AND GWH SOLD

VERSUS FORECASTED VALUES

YEAR	MONTH	PREDICTED LOAD (MW)	ACTUAL LOAD (MW)	PREDICTED SALES (GWH)	ACTUAL SALES (GWH)
1979	May	858	701	380	340
	Apr.	726	604	351	319
	Mar.	740	602	376	350
	Feb.	743	633	355	336
	Jan.	748	642	393	368
1978	Dec.	748	638	376	347
	Nov.	732	625	358	333
	Oct.	843	594	372	338
	Sept.	940	883	375	377
	Aug.	1,047	848	439	401
	July	1,047	828	454	384
	June	1,003	826	353	366
	May	861	766	337	325
	Apr.	636	563	319	298
	Mar.	648	590	338	330
	Feb.	651	615	320	316
	Jan.	655	629	32[illegible]	342
1977	Dec.	655	604	333	314
	Nov.	641	595	317	320
	Oct.	734	567	330	312
	Sept.	818	711	332	320
	Aug.	933	759	389	355
	July	933	872	402	400
	June	874	816	312	344
	May	750	766	316	338
	Apr.	594	576	300	288
	Mar.	605	560	317	309
	Feb.	608	575	300	289
	Jan.	612	604	306	338
1976	Dec.	612	600	318	320
	Nov.	598	586	308	299
	Oct.	703	517	365	286
	Sept.	783	694	340	310
	Aug.	893	800	396	358
	July	893	811	406	374
	June	836	715	360	327

2

TABLE 1.7-8 (Cont'd) Page 2 of 3

YEAR	MONTH	PREDICTED LOAD (MW)	ACTUAL LOAD (MW)	PREDICTED SALES (GWH)	ACTUAL SALES (GWH)
1976	May	718	556	339	276
	Apr.	556	515	285	268
	Mar.	556	546	304	283
	Feb.	569	535	283	266
	Jan.	573	539	318	294
1975	Dec.	646	548	299	280
	Nov.	632	523	290	257
	Oct.	660	537	303	278
	Sept.	735	743	332	272
	Aug.	838	754	251	335
	July	838	768	349	351
	June	785	750	299	315
	May	634	680	284	274
	Apr.	586	500	273	259
	Mar.	597	515	295	271
	Feb.	600	514	270	260
	Jan.	604	521	282	290
1974	Dec.	604	537		276
	Nov.	591	514		272
	Oct.	619	517		281
	Sept.	690	591		275
	Aug.	786	708		319
	July	786	746		368
	June	736	716		285
	May	632	589		275
	Apr.	549	493		260
	Mar.	559	493		273
	Feb.	561	501		254
	Jan.	565	489		279
1973	Dec.	565	494		265
	Nov.	553	510		265
	Oct.	575	538		282
	Sept.	640	612		285
	Aug.	730	768		341
	July	730	721		338
	June	683	677		304
	May	587	498		263
	Apr.	513	493		256
	Mar.	522	481		269
	Feb.	525	502		251
	Jan.	528	498		280

TABLE 1.7-8 (Cont'd) Page 3 of 3

YEAR	MONTH	PREDICTED LOAD (MW)	ACTUAL LOAD (MW)	PREDICTED SALES (GWH)	ACTUAL SALES (GWH)
1972	Dec.	514	514		275
	Nov.	507	501		265
	Oct.	514	479		265

TABLE 1.7-9

IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

GENERATING UNITS

UNIT	NAME PLATE RATING (MW)	NET TO SYSTEM (MW)	PRIMARY FUEL TYPE	IN-SERVICE DATE	PROJECTED RETIREMENT DATE	
Council Bluffs 3	725.85[a]	210.60[b]	Coal	1978	2018	
Riverside Station						
R-3	22.857	24.723	Coal	1937	1985	2
R-2hs	2.5	1.390	Coal	1937	1985	
R-4	43.294	51.382	Coal	1949	1995	
R-3hs	5.0	5.734	Coal	1949	1995	
R-5	128.0	141.140	Coal	1961	2006	
Moline Station						
M-5	17.143	19.960	Oil	1942	1991	
M-6	25.0	25.783	Oil	1953	1991	2
M-7	25.0	26.157	Oil	1955	1991	
Quad Cities[c] Station						
Unit 1	828.315	192.000	Nuclear	1972	2020	
Unit 2	838.315	192.333	Nuclear	1972	2020	
George Neal[d] Station						
Unit 3	494.8[a]	152.250	Coal	1975	2015	
Riverside Gas Turbines	67.764	60.752	Oil	1968	1993	2
Moline Combined Cycle	105.364	99.531	Oil	1970, 1976	1995	
Coralville Gas Turbines	67.764	63.440	Oil	1970	1995	
Moline Hydro	3.6	2.767	---	1942	1992	
Manson Diesel	1.0	0.995	Oil	1950	1981	
Net Capacity Available		1,270.937				2

[a]Equivalent MW, Nameplate shows kV amperes at 0.9 PF.

[b]Iowa-Illinois' share is 32.4 percent of unit.

[c]Iowa-Illinois has a 25 percent interest in the station.

[d]Iowa-Illinois has a 29 percent interest in the unit.

TABLE 1.7-10

SCHEDULED ADDITIONS AND RETIREMENTS OF

GENERATING UNITS ON IOWA-ILLINOIS GAS AND ELECTRIC COMPANY SYSTEM

UNIT	TOTAL UNIT CAPACITY (MW)	NET TO SYSTEM (MW)	PRIMARY FUEL TYPE	SCHEDULED DATE FOR ADDITION OR RETIREMENT	
Manson Diesel	1.0	0.995	Oil	Retire	1981
Ottumwa 1	675.0	125.00[a]	Coal	Add	1981
Louisa	650.0	300.00[b]	Coal	Add	1983
Riverside Station R-3	24.723	24.723	Coal	Retire	1985
Riverside Station R-2hs	1.390	1.390	Coal	Retire	1985
Carroll County - 1	1,120.0	168.0[c]	Nuclear	Add	1990[d]
Carroll County - 2	1,120.0	168.0[c]	Nuclear	Add	1991[e]
Moline Station M-5	19.960	19.960	Oil	Retire	1991
Moline Station M-6	25.783	25.783	Oil	Retire	1991
Moline Station M-7	26.157	26.157	Oil	Retire	1991
Riverside Station R-4	51.382	51.382	Coal	Retire	1995
Riverside Station R-3hs	5.734	5.734	Coal	Retire	1995
Riverside Gas Turbines	58.516	58.516	Oil	Retire	1993
Moline Combined Cycle	99.531	99.531	Oil	Retire	1995
Coralville Gas Turbines	63.440	63.440	Oil	Retire	1995
Moline Hydro	2.767	2.767	--	Retire	1992

1

2

[a]Iowa-Illinois share is 18.5 percent of the unit.

[b]Iowa-Illinois share is 46.2 percent of the unit.

[c]Iowa-Illinois share is 15.0 percent of the unit.

[d]Service date is fall of 1990. Unit not available for 1990 summer peak.

[e]Service date is fall of 1991. Unit not available for 1991 summer peak.

Revision 1
5/79

Revision 2
8/79

902181

TABLE 1.7-11

NET CAPABILITY, PEAK LOADS, AND RESERVE MARGINS 1979 THROUGH 1995

FOR IOWA-ILLINOIS GAS AND ELECTRIC COMPANY SYSTEM

	NET CAPABILITY (INCLUDING CARROLL COUNTY STATION)	PEAK LOAD	RESERVE MARGIN		
			MW RESERVE	PERCENT OF MARGIN[a]	EXCESS OR DEFICIENCY[b]
1979	1,271	1,047	224	21.4	67
1980	1,271	1,123	148	13.2	-20
1981	1,395	1,205	190	15.8	9
1982	1,395	1,287	108	8.4	-85
1983	1,695	1,373	322	23.4	116
1984	1,695	1,465	230	15.7	10
1985	1,670	1,564	106	6.8	-129
1986	1,670	1,659	11	0.7	-238
1987	1,670	1,760	-90	-5.1	-354
1988	1,670	1,867	-197	-10.6	-477
1989	1,670	1,981	-311	-15.7	-608
1990	1,835	2,102	-267	-12.7	-582
1991	1,928	2,230	-302	-13.5	-637
1992	1,925	2,366	-441	-18.6	-796
1993	1,867	2,510	-643	-25.6	-1,020
1994	1,867	2,663	-796	-29.9	-1,195
1995	1,647	2,825	-1,178	-41.7	-1,602

2

1

Note: Values in MW unless otherwise indicated.

[a]Percent reserve is reserve margin expressed as a percent of peak load.

[b]Based on required margin by MAPP of 15 percent.

Revision 1
5/79

Revision 2
8/79

902182

TABLE 1.7-12

GENERATING UNIT CAPABILITIES 1974-1979

ESTIMATED CAPACITY FACTORS 1979-1991

PLANT NAME	UNIT	TYPE[a]	FUNCTION[b]	SUMMER CAPABILITY IN MEGAWATTS 1974	1975	1976	1977	1978	1979	ESTIMATED 1979-1991 CAPACITY FACTORS IN PERCENT
Moline	3	FG	P	0	14	14	0	0	0	0
	4	FG	P	16	0	0	0	0	0	0
	5	FO	C	20	20	20	20	20	20	5-1 (Retire 1991)
	6	FO	C	26	26	26	26	26	26	5-1 (Retire 1991)
	7	FO	C	26	26	26	26	26	26	5-1 (Retire 1991)
	8	W	C	0	0	0	103	103	100	15-15
	GT	FO	C	66	66	66				
Riverside	1	FG	P	24	24	24	24	24	0	0
	3	FC	C	25	25	25	25	25	25	20-0 (Retire 1985)
	3HS	FC	C	6	6	6	6	6	6	20-1
	4	FC	C	51	51	51	51	51	51	25-20
	5	FC	B	141	141	141	141	141	141	45-30
	GT	FC	P	66	64	61	61	59	61	5-10
Coralville	GT	FO	P	66	70	64	63	63	63	5-5
Manson		FO	P	1	1	1	1	1	1	1-0 (Retire 1981)
Moline Hydro		H	B	3	3	3	3	3	3	90-80
Quad Cities	1	N	B	194	194	194	194	192	192	55-65
	2	N	B	194	194	194	194	192	192	55-65
Neal	3	FC	B	0	0	151	149	152	152	55-65
Council Bluffs	3	FC	B	0	0	0	0	0	211	55-55

[a]Unit Type: FG - Fossil Gas; FO - Fossil Oil; F - Fossil Coal; H - Hydroelectric; N - Nuclear; W - Waste Heat.

[b]Function: B - Base Load; C - Cyclic Operation; P - Peaking.

TABLE 1.7-13 Page 1 of 3

LOAD DURATION CURVES FOR IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

PERCENT TIME	PERCENT LOAD 1972	1973	1974	1975	1976	FORECAST
0	100	100	100	100	100	100
1	90	90	94	94	87	91
2	84	82	86	88	83	88
3	80	78	80	84	78	80
4	76	76	78	80	75	77
5	74	72	74	76	74	74
6	72	70	72	74	73	72
7	70	68	70	72	71	70
8	70	66	68	70	70	68
9	68	66	68	68	69	67
10	66	64	68	66	68	66
11	66	64	66	66	67	65
12	66	64	66	66	67	65
13	66	64	66	64	66	65
14	64	64	64	64	65	64
15	64	64	64	64	65	64
16	64	62	64	63	64	63
17	64	61	64	62	64	63
18	64	60	64	62	63	62
19	63	60	64	62	63	62
20	62	60	64	62	62	62
21	61	60	63	61	62	61
22	61	60	63	61	61	61
23	60	60	62	60	61	61
24	60	60	62	60	61	60
25	60	60	62	60	61	60
26	60	59	61	60	60	60
27	60	59	61	60	60	60
28	60	58	60	60	60	59
29	60	58	60	60	59	59
30	60	58	60	60	59	59
31	59	57	59	59	59	59
32	59	57	59	59	58	58
33	58	56	58	58	58	58
34	58	56	58	58	58	57
35	58	56	58	58	58	57
36	57	56	58	57	57	57
37	57	56	58	57	57	57
38	56	56	58	56	56	56
39	56	56	58	56	56	56
40	56	56	58	56	56	56
41	55	55	57	55	55	55

TABLE 1.7-13 (Cont'd) Page 2 of 3

PERCENT TIME	PERCENT LOAD 1972	1973	1974	1975	1976	FORECAST
42	55	54	56	54	55	55
43	54	53	55	53	54	54
44	54	52	54	52	54	53
45	54	52	54	52	53	53
46	53	51	53	51	52	52
47	52	51	53	50	52	51
48	51	50	52	49	51	51
49	50	50	52	48	51	50
50	50	50	52	48	50	50
51	49	49	51	47	49	49
52	49	49	50	47	49	49
53	48	48	49	46	48	48
54	48	48	48	46	48	48
55	48	48	48	46	47	47
56	47	47	47	45	47	47
57	47	46	47	45	46	46
58	46	45	46	44	46	46
59	46	44	46	44	45	45
60	46	44	46	44	45	45
61	45	43	45	43	44	44
62	44	43	45	43	44	44
63	43	42	44	42	44	43
64	42	42	44	42	43	43
65	42	42	44	42	43	42
66	41	41	43	41	43	42
67	41	41	43	41	42	41
68	40	40	42	40	42	41
69	40	40	42	40	41	41
70	40	40	42	40	41	40
71	39	39	41	39	41	40
72	39	39	41	39	40	39
73	38	38	40	38	40	39
74	38	38	40	38	40	39
75	38	38	40	38	40	38
76	37	37	39	37	39	38
77	37	37	39	37	39	38
78	36	36	38	36	38	37
79	36	36	38	36	38	37
80	36	36	38	36	38	36
81	36	36	37	35	37	36
82	36	36	37	35	37	36
83	36	36	36	34	37	36
84	36	36	36	34	36	35
85	36	36	36	34	36	35
86	35	35	36	34	36	35

TABLE 1.7-13 (Cont'd) Page 3 of 3

PERCENT TIME	PERCENT LOAD 1972	1973	1974	1975	1976	FORECAST
87	34	34	36	34	35	35
88	34	34	36	34	35	34
89	34	34	36	34	35	34
90	34	34	36	34	35	34
91	32	34	36	32	34	33
92	32	34	34	32	34	33
93	32	34	34	32	33	33
94	32	32	34	32	33	32
95	32	32	34	30	32	32
96	32	32	32	30	32	31
97	30	32	32	30	31	31
98	30	30	30	28	30	29
99	28	30	30	28	28	28
100	28	30	30	28	28	28

TABLE 1.7-14

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT REGION

SJMMER PEAK LOADS AND CAPABILITIES

YEAR	PEAK LOAD (MW)	CAPABILITY (MW)	PERCENT CAPABILITY MARGIN
1973	13,959	15,855	13.6
1974	13,706	16,991	24.0
1975	14,503	18,464	27.3
1976	14,938	19,920	33.4
1977	16,586	21,062	27.0

1.8 OTHER OBJECTIVES - IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

Carroll County Station Units 1 and 2 are proposed for production of electrical energy with no other objectives planned.

1.9 CONSEQUENCES OF DELAY - IOWA-ILLINOIS GAS AND ELECTRIC COMPANY

A delay in the availability of the capacity of the proposed Carroll County Station would involve decreased system reliability and economic penalties to the owners.

Power could be purchased from other members of MAPP if it were available. There is not, however, enough capacity presently committed in 1991 and 1992 that a purchase of power could be arranged.

Delaying the proposed Carroll County Station even 1 year would increase the capital cost of the units because of escalation in price of materials and labor. Delaying the unit also means that some electricity would need to come from less efficient, higher cost generation, or relatively high cost purchases. If the delay were long, it would also mean that at some times during the late 80s customers would find their supply of electricity restricted. This restriction could result in reduced and interrupted electric service to all classes of customers. Residential and commercial customers would not only be inconvenienced, but essential services, such as elevator operation, could be interrupted at critical times. Industrial production would be affected, with the reduced output having a negative impact on the economic climate of the IIG&E service areas.

2.1.2 Population Distribution

The 1975 population distribution within 50 miles of the proposed Carroll County Station has been estimated based on the 1975 population data provided by the Bureau of the 1 Census of the U.S. Department of Commerce for the states of Illinois, Iowa, and Wisconsin (U.S. Bureau of the Census, 1977a). The populations of the portions of the townships and incorporated areas within a given sector were added together, resulting in an estimated population for the given sector. This was done for each of the 160 sectors.

The method for making the population projections for 1987, 1990, 2000, 2010, 2020, and 2030 for each of the 160 sectors formed by the concentric circles and the radial lines is discussed in Subsection 6.1.4.2.2.

2.1.2.1 Population Within 10 Miles

The 1975 population of the area within 10 miles of the Carroll County Station site was estimated to be 13,712. Most of this area is located in Carroll County, Illinois, but small portions of it are in Whiteside County, Illinois, and Clinton and Jackson counties, Iowa. The area is rural and has a population density of only 46 persons per square 1 mile. The only incorporated areas within the 10-mile radius are the towns of Savanna (4,651 persons), Mt. Carroll (2,150 persons), Thomson (660 persons), and Chadwick (653 persons) in Illinois and Sabula in Iowa (1,014 persons). The distribution of the population in the sectors formed by the concentric circles and radial lines is presented in 1 Figure 2.1-4.

The population of the area within 10 miles of the station is projected to be 15,142 in 1990; 15,659 in 2000; 17,289 2 in 2010; 18,156 in 2020; and 19,064 in 2030 (See Figure 2.1-8 for a detailed depiction of the population distribu- 1 tion). The population density of year 2030 is projected to be 61 persons per square mile (see Table 2.1-2 for the population distributions and densities for the life of the of the station).

Projections of the age distribution of the population were available at 5-year intervals. The year closest to the likely midpoint of the station operating life was 2005. The data on age distribution of the projected population are presented in Table 2.1-2a. 1

Revision 1
5/79

Revision 2
8/79

302190

2.1.2.2 Population Between 10 and 50 miles

The 1975 population of the area within 10 to 50 miles of
the proposed station was estimated to be 738,109. Although
this area is predominantly rural, it does include two
large metropolitan areas -- the Quad-Cities of Davenport,
Rock Island, Moline and Bettendorf in Illinois and Iowa,
and Dubuque, Iowa -- as well as several smaller cities --
Freeport, Sterling - Rock Falls, and Dixon in Illinois,
and Clinton in Iowa. The city of Rockford, Illinois lies
just beyond the 50-mile radius. The population density of
this area in 1975 was estimated to be 96 persons per 1
square mile. The distribution of the population in the
sector formed by the concentric circles and the radial
lines is presented in Figure 2.1-7.

The population of the area within 10 to 50 miles of the
proposed plant is projected to be 809,700 in 1990; 866,357 2
in 2000; 915,827 in 2010, 957,174 in 2020, and 996,990 in
2030 (see Figure 2.1-9 for a detailed depiction of the
population distribution). The population density within
10 to 50 miles in year 2030 is projected to be 132 persons
per square mile (see Table 2.1-3). 1

The 1975 population of the area within 50 miles of the
proposed plant was estimated to be 752,461. The population 1 2
of this area is projected to be 824,842 in 1990 and
1,016,054 in 2030. This area includes all of Carroll,
Whiteside, Jo Daviess, and Stephenson counties in Illinois,
and Jackson and Clinton counties in Iowa. It also includes
portions of 13 other counties: Bureau, Henry, Lee, Ogle,
Rock Island, and Winnebago in Illinois; Cedar, Dubuque,
Jones, and Scott in Iowa; and Grant, Green, and Lafayette
in Wisconsin. The population density of this area in 1975
was 96 persons per square mile. It is projected to
increase to 129 persons per square mile in year 2030.

The age distribution of the projected population in the
year 2005 was based upon the projected age distribution of
the United States population in that year. The data are 1
presented in Table 2.1-2a.

In accordance with Regulatory Guide 4.7, General Site
Suitability Criteria for Nuclear Power Stations, the
average population density over a 30-mile radial distance
from the station has been projected to be 75 persons per
square mile in 1987 and 93 persons per square mile in 2030
(see Table 2.1-3). The nearest population center (as
defined in 10 CFR 100) is Clinton, Iowa. Table 2.1-3a lists 1
selected communities within 50 miles of the site, and lists
their respective distances from the site.

REVISION 2 8/79

CARROLL COUNTY NUCLEAR GENERATING STATION - UNITS 1 & 2
SITE SUITABILITY - ENVIRONMENTAL REPORT

FIGURE 2.1-5 902192

SITE BOUNDARY, RESTRICTED AREA BOUNDARY, AND EXCLUSION AREA

2.6.2 Features of Interest - Station Site

There are no sites on the station property that are included or are eligible for inclusion in the "National Register of Historic Places" (Federal Register, 1978), the "National Registry of Natural Landmarks" (Federal Register, 1975) or the other listings of locally significant sites.

Many areas of federal and local historical interest, however, do exist in the area. Table 2.6-1 lists and briefly describes these historic sites and markers located within the area around the site as supplied by information from various local sources (see references Chapter 13.0).

2.6.2.1 Archaeology

At the completion of the archaeological surveys of the Carroll County Station conducted by archaeologists from Archaeological Research Associates and the University of 2
Wisconsin at Milwaukee, 37 archaeological sites have been located either within the site boundary or close to the site.

The cultural components, previously described in Section 2.6.1, of the archaeological sites are listed below:

Number of Archaeological Sites	Cultural Affiliation
1	Middle Woodland Period
2	Late Woodland Period
5	Woodland Period
1	Historic Period
22	Indeterminate
2	Archaic-Late Woodland-Historic Components
3	Late Archaic-Early Woodland Components
1	Late Archaic-Early Woodland-Late Woodland Components

In addition, three Woodland sites contained mound groups.

Archaeological Monitoring/Testing Plan - Of the 37 archaeological sites located on or near plant property, 6 sites initially were determined to be directly or indirectly impacted. Commonwealth Edison's plan to monitor and/or conduct test excavations on these six sites is outlined below. In preparing this plan, careful consideration has been taken to include any possible construction activity impact, even if not yet planned.

A Woodland mound group is east of the activity areas of the switchyard, and construction worker parking and access. Due to the importance of this site, all

activity, both during construction and operation, has been routed away from the mound group. In addition, the east side of the mound group will be temporarily fenced during construction activity in the area, and monitored by periodic visits by archaeologists and Commonwealth Edison personnel to ensure that the mound group is not being impacted. The fence will be temporary, and removed during station operation, so the mound group will not be drawn to the attention of possible pot-hunters and vandals. The mound group, and its associated cultural material, will be preserved as a cultural resource.

A solitary mound is in the area of a possible southern entrance to the site by construction workers. Upon examination of the area by archaeologists and Commonwealth Edison personnel, it was determined that the mound would not be adversely impacted. If the southern access is ever developed, the mound will receive periodic visits by archaeologists and CECo personnel to ensure that it, and its cultural material, are preserved.

A long Late Archaic-Early Woodland-Late Woodland habitation site will be partially impacted by the pipeline construction to the river screen house. All construction activity will be restricted, through the use of temporary fences, to a 225-foot wide corridor through the site. The remainder of the site owned by CECo (CECo does not own the entire property that the site is on) will not be impacted by any construction activity. Within the corridor through the site which will receive impact, archaeologists from the University of Wisconsin at Milwaukee will conduct a controlled surface collection with accompanying test excavations. This work will be conducted prior to construction. In addition, preliminary test excavations were conducted by the same archaeologists at this site in 1974 (University of Wisconsin, 1975). Well over half of the site will remain free of any impact, and the portion to be impacted will first have cultural material retrieved and evaluated prior to construction. 1

An Archaic-Late Woodland habitation site will be impacted totally by Unit 1 cooling tower construction. Test excavations have already been completed on this site (University of Wisconsin, 1975) and all culturally significant material has been removed and analyzed. At the conclusion of the investigation, the following evaluation was made:

"The small size of this site, in conjunction with its lack of intensive habitation debris, and lack of largely undisturbed cultural deposits render it of extremely little potential value for adding to our knowledge of the prehistory of the region. For this reason, we recommend that this site be given no further archaeological attention" (University of Wisconsin, 1975).

An indeterminate campsite lies close to the railroad spur line to the main plant facilities. Test excavations will be conducted by the University of Wisconsin archaeologists to determine the exact periphery of the site. If any portion of the site lies in the area to be impacted, further excavations will be undertaken to recover all cultural material from the impact area.

A Late Archaic-Early Woodland site lies south of the discharge pipe to the Mississippi River. So as to definitely avoid impacting the site, the discharge pipe, and all its associated construction activity, has been moved 50 feet north of its present location. The site, and all its cultural material, will be preserved, and the site will receive periodic visits from archaeologists and CECo personnel to ensure its preservation.

The remaining 31 archaeological sites on or near the Carroll County Station property are removed from any construction or operation impact area, and will remain in their current state, with all cultural material contained within the sites being preserved. 1

2.6.3 Features of Interest - Transmission Line Rights-of-Way

A survey of the historic, archaeological, architectural, scenic, cultural, and natural features will be conducted on the transmission line rights-of-way out of Carroll County Station before station construction. When the significance of any features found has been evaluated, this assessment will be submitted to the State Historic Preservation Officers for Illinois and Iowa for approval of preservation action, if needed, planned by the respective utilities.

2.6.4 Methodology

A literature search was undertaken to determine what sites of cultural importance were known to exist onsite. No European settlement activity is reported within the Carroll County Station. For literature consulted refer to references cited in Chapter 13.0. In addition, field investigations onsite were carried out in the event that European settlements

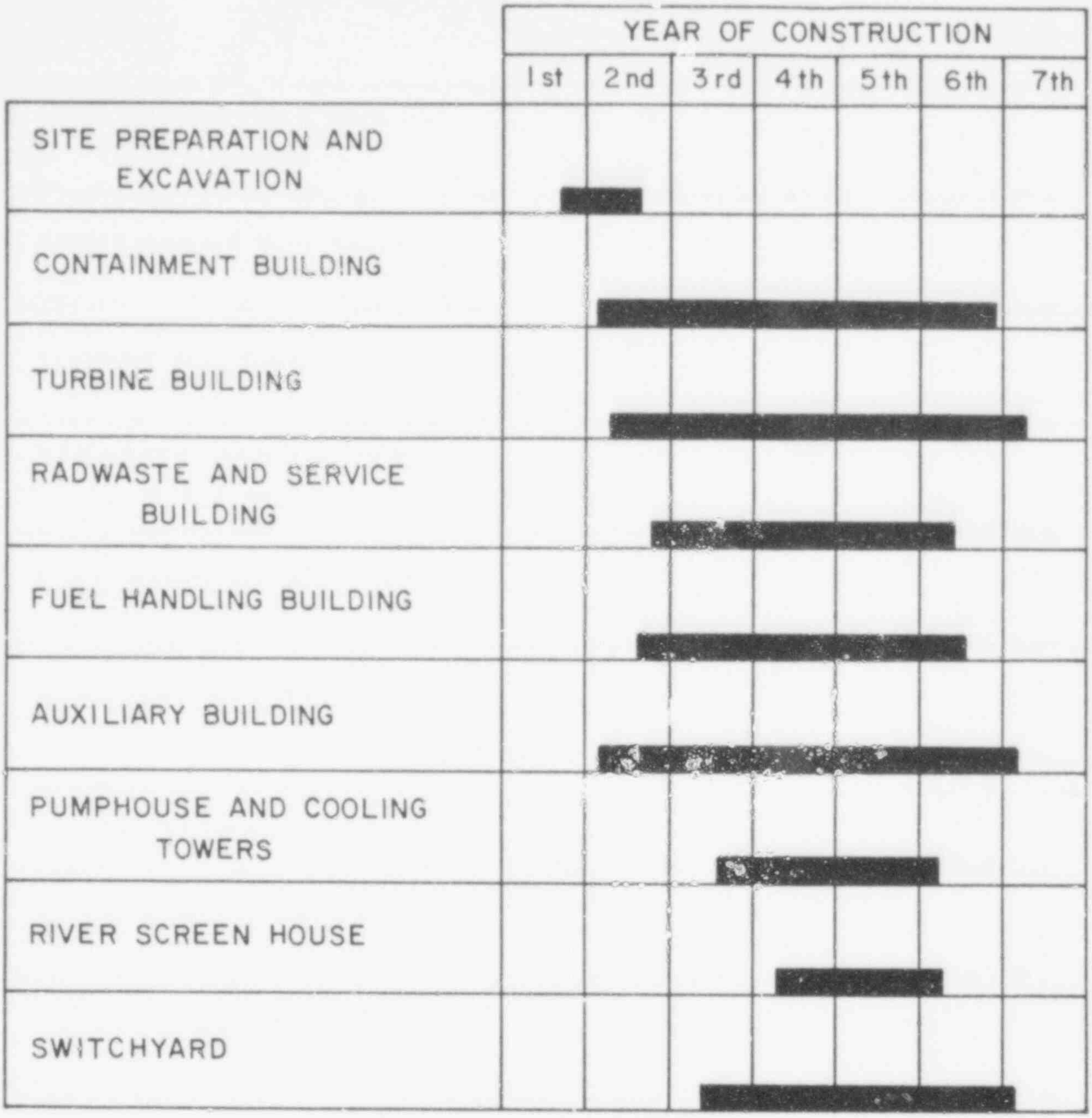
not yet recorded on public records were located onsite. Again, none were found.

Two archaeological surveys were conducted at the Carroll County Station site. The first survey was performed during 1974 by Archaeological Research Associates, and the second survey was done during 1978 by the University of Wisconsin of Milwaukee on those portions of the site obtained since 1974 (University of Wisconsin, 1974, 1975, and 1978).

The archaeological survey consisted of both a literature search and a field examination of the project area, including the pipeline corridor. Prior to field work, the literature search revealed two archaeological sites on record. For both the 1974 and 1978 surveys, field pro- 2
cedures included walking the entire area at 15-meter (approximately 50 feet) intervals. During the 1978 survey, rapid subsurface testing was employed to ensure adequate survey coverage in areas where vegetation obscured the ground surface. Both surveys' field procedures also included sketch mapping the limits of any archaeological sites located, collecting materials indicative of the prehistoric and early historic utilization of each site, comparing these material remains with known archaeological data, and appraising the significance of each site with reference to its regional context. 1

Test excavations were conducted on two archaeological sites in 1975 by the University of Wisconsin at Milwaukee. Metric test units were taken down to sterile soil, all soil was screened through a 1/4-inch mesh, and profile and plan view drawings were made of all units and features.

After the materials and records from the surveys and test excavations were returned to the University laboratory, the data were processed and analyzed, and maps and photographs prepared. The data are currently under the curatorship of the University of Wisconsin at Milwaukee. All archaeological site locations and detailed site descriptions are the property of the State of Illinois and are not for public distribution.



SOURCE:
COMMONWEALTH EDISON
COMPANY (1977)

REVISION 2 8/79

CARROLL COUNTY NUCLEAR GENERATING STATION - UNITS 1 & 2
SITE SUITABILITY - ENVIRONMENTAL REPORT

FIGURE 4.1-1

CONSTRUCTION SCHEDULE FOR UNIT 1

902197

CHAPTER 8.0 - ECONOMIC AND SOCIAL EFFECTS OF STATION CONSTRUCTION AND OPERATION

8.1 INTRODUCTION

The purpose of this section is to assess the potential social and economic effects of the proposed Carroll County Nuclear Generating Station - Units 1 and 2 (Carroll County Station). The proposed facility will be constructed in Carroll County, Illinois jointly by the Commonwealth Edison Company (CECo), the Interstate Power Company (ISP), and Iowa-Illinois Gas and Electric Company (IIG&E). The section has been prepared to satisfy the U.S. Nuclear Regulatory Commission's (NRC) requirements as specified in Chapter 8 of Regulatory Guide 4.2, Revision 2. The findings of this report are based on the construction and operation of two, 1,120-MW reactors.

This work was performed for Commonwealth Edison Company by Public Research, Inc. during 1977 and 1978. Since the time that the study was completed, the unit completion 2
dates have been delayed for Carroll County Units 1 and 2 until the fall of 1990 and 1991, respectively.

Since most of the potential effects would be associated with the relocation of construction-phase and operational-phase workers and their families, relocation projections are the most important element of this section. The projections and a detailed discussion of the method employed in making these projections are presented in Section 8.2. Assessments of potential housing costs, health care and educational system costs, water and sewer facility costs, etc. are based on these relocation projections. The section also contains a detailed description of the study area's socioeconomic environmental data base. Data are presented that indicate the current status of the study area and its history, as well as future trends.

8.1.1 Definition of the Study Area

The effects of construction and operation of the Carroll County Station would be felt at both local and regional levels. For purposes of assessing the potential local effects, the study area has been divided into areas within various driving distances of the site.

The first division includes the area within 10 driving miles of the site of the proposed station entirely on the east side of the Mississippi River. This area is comprised of the incorporated municipalities of Savanna, Mount Carroll,

and Thomson (all in Illinois); and the unincorporated rural areas outside these municipalities.

The second division includes the area within 11 to 20 driving miles of the station site; and includes the Illinois municipalities of Fulton, Lanark, Milledgeville, and Chadwick, the unincorporated rural areas within the 11- to 20-mile driving distance, and Sabula, Iowa, an island community in the Mississippi River.

The third division of the study area encompasses a 21- to 30-mile driving distance from the station site; and includes the Illinois municipalities of Morrison, Hanover, Forreston, Shannon, Elizabeth, and Pearl City the Iowa municipalities of Clinton and Preston, and the unincorporated rural areas.

For other purposes, two additional divisions are used: a 31- to 40-mile driving distance and a 41- to 50-mile driving distance. All communities with a population over 500 within 50 driving miles of the station site are listed in Table 8.1-1.

The regional impact area includes the Illinois counties of Jo Daviess, Stephenson, Carroll, Ogle, Whiteside, and Lee; and the Iowa counties of Jackson and Clinton (Figure 8.1-1). The larger impact region shown on Figure 8.1-1 is approximately bounded by the metropolitan areas of Rockford, Illinois to the northeast; Dubuque, Iowa to the northwest; and the Quad Cities of Moline, East Moline, Davenport, and Rock Island to the southwest. As the study will show, the principal social and economic impacts due to the construction and operation of the proposed station will occur within 0 to 20 driving miles of the site.

Due to the fact that there are no bridges crossing the Mississippi River into Iowa immediately west of the station site [the nearest bridge is approximately 3 River Miles (RM) north of this point near Savanna, Ill.], the social and economic impacts are confined to the Illinois side of the river.

8.1.2 Spatial Relationship of Site to Study Area

The Carroll County Station site is located in the western portion of Carroll County, Illinois, approximately 3 miles east of the Mississippi River. Carroll County is a rural agricultural county as are the other counties in the regional impact area.

The station site is located in the approximate center of a triangle of urban population centers formed by Dubuque,

Iowa, located on the Mississippi River approximately 50 air miles northwest of the site; Rockford, Illinois, approximately 50 miles northeast of the site; and the Quad Cities area of Illinois and Iowa on the Mississippi River approximately 50 miles southwest of the site (see Figure 8.1-1).

8.1.3 Municipalities in the Study Area

Because of the rural nature of the study area, most of the municipalities had less than 5,000 persons in 1975 (see Table 8.1-1). Within 10 driving miles of the site, there were three municipalities with populations over 500 having a total 1975 population of 7,461. Between 11 and 20 driving miles from the site, there were 5 municipalities of over 500 population, with combined 1975 populations of only 8,028.

Municipalities were larger in areas beyond 20 driving miles. Primarily due to of Clinton, Iowa, the population in the region 21 to 30 miles from the site totaled 43,600 in 1975.

The total population of all municipalities with a population over 500 within 50 miles of the station site was 174, 656 in 1975.

8.1.4 Topography of the Study Area

Study-area topography varies widely, with the Mississippi River predominant feature which runs from north to south through the study area. Flat alluvial bottomlands are found adjacent to the river with steeply sloping uplands located on the periphery of the floodplains.

The topography of the area was influenced primarily by glaciation. The Illinois glacier covered all of the study area except the northwest corner of Carroll and Jo Daviess counties. The station site is located on a predominant bluff in the unglaciated portion of Carroll County.

Beyond the floodplain and bluff areas of the river to the west in Iowa and east in Illinois, the topography consists of flat land with areas of gently rolling hills.