National Hydroelectric Power Resources Study

The Magnitude and Regional Distribution of Needs for Hydropower — Phase I
1978 Electric Power Demand and Supply

Volume III
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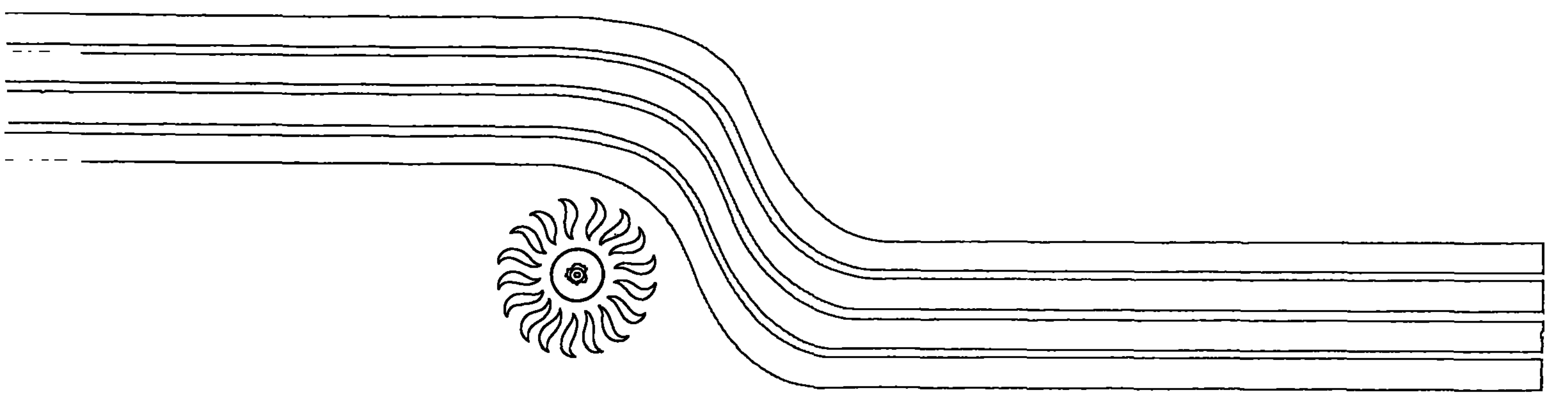

The Magnitude and Regional Distribution of Needs for Hydropower — Phase I 1978 Electric Power Demand and Supply

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEEDS FOR HYDROPOWER

THE NATIONAL HYDROPOWER STUDY

Phase I - 1978 Electric Power
Supply and Demand

VOLUME III

Institute for Water Resources
U.S. Army Corps of Engineers
Fort Belvoir, Virginia

September 1981

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FOREWORD

Authorization

Authorization to perform this study was granted by the U.S. Army Corps of Engineers (CORPS), Institute for Water Resources (IWR), in a letter to Harza Engineering Company (Harza) dated 21 September 1978. The work is being performed under Contract Number DACW72-78-C-0013, regarding "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study."

Objective

The objective of this report is to summarize the present status of electric power demand and supply in the United States. This report will be attached as an appendix to the Phase II report presenting the results of the study concerning the magnitude and regional distribution of needs for hydropower. The Phase I report describes the current role of hydroelectric power in the United States.

Scope of Work

The overall study area is the electrical power system in the fifty states. An analysis is made of the capability and energy production of the present electric power systems delineated by study regions. The study regions are selected in accordance with the following guidelines:

(a) the maximum size of a study region is the area represented by one of the nine National Electric Reliability Councils (NERC) within the contiguous United States. The States of Alaska and Hawaii each are treated as separate study regions.

(b) smaller subregions within those of "a" above may be defined by power pools or coordinating groups.

The data used in the study are published and readily available information. Data on historical and present electric power system loads and capabilities have been obtained from Federal and State agencies, private institutions, regional coordinating councils, and individual utilities.

Content of the Report

The report consists of twelve chapters with supporting tables, a glossary of terms and exhibits. Chapter I contains a description of the current electric power situation in the United States. Each of the following nine Chapters (Chapters II through X) of this report deals with one of the nine specific NERC regions and the individual study subregions within the region.

Chapters XI and XII describe current electric power situation in the State of Alaska and the State of Hawaii.

Harza Participants

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Chapter I

THE ELECTRIC POWER DEMAND AND SUPPLY IN THE UNITED STATES

This chapter summarizes the current electric power situation in the contiguous United States, the State of Alaska, and the State of Hawaii. The situation is described in terms of the calendar year 1977, since that is the most recent full year for which complete data are available. The following information is presented and discussed:

(1) Capacity and energy demands and the resulting load factors for 1977.

(2) Ownership and the types of generation sources.

(3) Categories of fuels used for generation.

(4) A comparison between the present electric demand and existing generation sources to evaluate the generating reserve margin.

(5) The role of hydroelectric power in the present electrical system.

(6) The magnitude and ownership of existing hydroelectric generating plants, both conventional and pumped storage.

Current Electric Power Situation

The electric utility power system in the continental United States is made up of nine Regional Electric Reliability Councils. They are:

ECAR - East Central Area Reliability Coordination Agreement
ERCOT - Electric Reliability Council of Texas
MAAC - Mid-Atlantic Area Council
MAIN - Mid-America Interpool Network
MARCA - Mid-Continent Area Reliability Council Agreement
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
WSCC - Western Systems Coordinating Council

These nine regional groups of power suppliers, whose boundaries are shown on Exhibit I-1, form the National Electric Reliability Council (NERC). NERC was formed voluntarily by the electric utility industry in 1968 and incorporated in 1975. Its purpose is to augment the reliability and adequacy of bulk power supply of the electric utility systems in North America. Regional council memberships also comprise the Canadian systems in the provinces of Ontario, British Columbia, Manitoba, and New Brunswick. The Canadian electric utility systems are not included in this report.

Data concerning bulk electric power demand and supply in the contiguous United States are from reports submitted to the Department of Energy on April 1, 1978, by the Regional Electric Reliability Councils [I-1][1/]. The current council reports continue the annual series established by Federal Power Commission (FPC) Order 383-3 (issued March 10, 1970) and modified by subsequent Orders 383-3, 383-4, and 383-5. Most of the information on electrical systems in the State of Alaska is from "The 1976 Alaska Power Survey" [I-2] and the "Alaska Electric Power Statistics" [I-3]. For the State of Hawaii, data on electric loads and power systems were provided directly by the utilities in that state.

Demographic and economic data are from the 1972 OBERS Projections of Regional Economic Activity in the U.S. [I-4]. OBERS is an acronym signifying a unified effort of the former Office of Business Economics (OBE) and the Economic Research Service (ERS). In 1972, the OBE was renamed the Bureau of Economic Analysis (BEA), and will be so referred to in this report.

One set of areas for which OBERS presents historical and projected data are the 173 functional economic areas delineated by the BEA for economic analysis. Aggregations of BEA economic areas approximate the NERC regions and sub-regions, as shown on Exhibit I-2, and listed on Exhibit I-3. The historical data from OBERS for the BEA areas are summed to obtain earnings, income, and population for each NERC region and sub-region.

Current Electrical Demand

The electric power requirements in the entire nation for 1977 are summarized in Table I-1. Peak hourly demand for the months of July and December, annual net energy, and annual load factor are shown for each Regional Electric

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1/ Figure in brackets refers to number of reference listed at the end of the chapter.

Table I-1

ELECTRIC POWER REQUIREMENTS 1977
IN THE UNITED STATES
Actual Reported 1/

Council	Peak Demand - MW July 2/	December	Annual Net Energy GWh	Approximate Annual Load Factor
ECAR	62,306	59,136	365,526	0.67
MAAC	32,306	26,723	164,135	0.58
MAIN	33,404	26,439	161,081	0.55
MARCA	17,549	15,097	85,738	0.56
NPCC	35,448	33,767	194,212	0.63
SERC	79,332	73,861	442,233	0.64
SWPP	36,514	25,226	179,549	0.56
Sub-Total	296,859	260,249	1,192,474	0.61
	August	December		
WSCC	64,926	61,525	385,887	0.68
ERCOT	26,819	17,950	136,413	0.58
Contiguous U.S.	388,604 3/	339,724	2,114,774	0.62
	July	November		
Alaska	342 4/	538	2,262	0.48
		December		
Hawaii	984 5/	1,090	6,160	0.65
U.S. Total	389,930	341,352	2,123,196	0.62

NOTES:

1/ As reported by the Electric Utilities to the Department of Energy.

2/ Although the seven interconnected Councils had their summer peaks in the same month, diversity in time of occurrence makes the "sub-total" somewhat larger than the actual coincident "sub-total." The magntitude of the difference is not readily ascertainable but is probably in the range of 1% to 3% of the "sub-total" shown.

3/ The "U.S. Total" is not the actual simultaneous total peak demand, which cannot be readily ascertained. It is shown only to indicate the order of magnitude of the U.S. demand.

4/ Load shown is for July. The annual peak was in November, with a secondary peak of 423 MW in March.

5/ The load shown is for July. The annual peak was in December with no intermediate peak seasons. Peak load was at a minimum in June.

Sources: 1. Contiguous U.S.: U.S. Department of Energy, "Electric Power Supply and Demand 1978-1987 for the Contiguous United States," DOE/ERA-0018, July, 1978.

2. Alaska and Hawaii: FERC - Form No. 12 E-2.

Reliability Council and for the States of Alaska and Hawaii. The electric power requirements of the nine Council regions are actual data reported by the the Reliability Councils. The summer peak demand for all councils except WSCC and ERCOT is reported as occurring in July. The summer peaks of WSCC and ERCOT were in August. The 1977-78 winter peak period demand for all the Councils is projected to occur in January 1978 but the December 1977 demand is shown in Table I-1 to restrict the data to actual 1977 experience. The difference between the peak demands in December and the following January is not large in most Councils [I-5].

Current Electrical Supply

The electric power systems in the fifty states vary greatly in size, type of ownership, and range of functions. In the United States the electric utilities are made up of the following six distinct ownership segments:

(1) Investor-owned, (publicly-regulated by governmental agencies)
(2) State-chartered authorities
(3) Municipal systems
(4) Customer-owned cooperatives
(5) Federal (including the Tennessee Valley Authority)
(6) Industrial (which are not included in this report).

Most systems which serve large population centers perform the functions of generation, transmission and distribution. In rural and small urban areas, there are many systems which provide distribution exclusively, and others that generate some power while relying on firm purchases to meet the remainder of their requirements. These are mostly relatively smaller systems and are largely municipal and cooperative in ownership [I-6]. Over the years utilities tend to consolidate to improve economy as shown in Table I-2.

Table I-3 shows the current ownership patterns in terms of generating capability. Investor-owned publicly-regulated systems clearly constitute the dominant segment of generation sources, about 79% of the national total capability.

Table I-4 shows breakdowns of existing capability by types of generating plants in each region and the entire United States for the year 1977. Coal-fired generating plants constitute the largest share, about 38% of the nation's total capability. Oil-fired steam plants represent 18%, the next largest share. Conventional and pumped storage hydroelectric plants together make up nearly 14% of the national total capability.

Table I-2

NUMBER OF ELECTRIC UTILITY COMPANIES - CONTIGUOUS U.S.

Ownership	1927	1937	1947	1957	1968
Investor-Owned	2,135	1,401	858	465	405
Public, Non-Federal	2,198	1,878	2,107	1,890	2,075
REA Cooperatives	-	192	887	1,026	960
Federal*	1	3	4	5	5
TOTAL	4,334	3,474	3,856	3,386	3,445

*Marketing Agencies

Source: Federal Power Commission, National Power Survey 1970.

Fuels for Electric Generation

The net electrical energy generated in 1977 by principal energy sources is summarized in Table I-5. The basic data for the computations of the breakdown of net energy generated in 1977, in the contiguous United States were taken from the "Eighth Annual Review" by NERC [I-7]. Coal contributes 46.3% of the total energy generated in the contiguous United States, oil 16.9%, natural gas 13.7%, nuclear 12.4%, hydro 10.3%, and geothermal and other energy sources 0.4%. In the State of Hawaii, 91.6% of total energy generated is from oil, 0.3% from hydro. Data for the State of Hawaii are based on the net energy generated reported in FERC (FPC) Form No. 12 [I-8].

Transmission System

The electric utility power system in the contiguous United States is made up of three component networks.

The first single network comprises the seven strongly-inter-connected Council areas (ECAR, MAAC, MAIN, MARCA,

Table I-3

UNITED STATES
OWNERSHIP OF GENERATION SOURCES FOR 1977
(percent of total capability)

Council or State	Summer Capability MW	Investor-Owned	State	Municipal	Cooperative	Federal
ECAR	82,102	94.0	-	2.0	4.0	-
MAAC	44,253	100.0	-	-	-	-
MAIN	40,378	93.4	-	1.7	1.7	-
MARCA	21,236	64.0	13.9	1.1	9.4	11.6
NPCC	50,173	85.7	12.8	1.5	-	-
SERC	105,254	68.1	1.4	4.2	0.3	26.0
SWPP	43,892	85.5	1.2	5.0	3.4	4.9
WSCC	92,929	54.1	10.0	12.5	1.1	22.3
ERCOT	37,029	81.5	3.5	13.3	1.7	-
Contiguous U.S.	517,246	78.4	4.2	5.1	2.1	10.2
Alaska 1/	908	5.7	-	25.4	60.5	8.4
Hawaii 2/	1,462	100.0	-	-	-	-
U.S. Total	519,616	78.3	4.2	5.1	2.2	10.2

NOTES: 1/ Includes utilities and non-utilities. 1975 Data.
2/ Includes utilities and agricultural processing companies.

Table I-4

EXISTING CAPABILITY BY TYPE OF PLANTS
(Actual 1977)

	ECAR	MAAC	MAIN	MARCA	NPCC	SERC	SWPP	WSCC	ERCOT	Contiguous U.S.	Alaska 7/	Hawaii 8/	Total
Capability, MW													
Summer	82,102	44,253	40,378	21,236	50,173	105,254	43,892	92,929	37,029	517,246	908	1,462	519,616
Winter	83,886	46,783	41,285	21,847	52,009	106,901	43,692	93,082	37,029	526,514	908	1,462	528,884
Generation Mix, 1/ %													
Nuclear	3.7	13.4	15.9	17.2	14.9	13.2	1.9	2.7	-	8.5	-	-	8.5
Steam - Gas 3/	0.1	-	0.2	0.9	-	0.2	63.7	2.3	83.6	11.7	1.6	-	11.7
Steam - Coal 3/	80.3	33.2	66.6	50.9	7.6	48.9	11.3	17.4	11.1	37.8	5.9	-	37.6
Steam - Oil 3/	6.7	27.0	7.2	2.6	49.4	17.2	8.8	25.7	-	18.0	6.2	82.9	18.1
Combined Cycle - Oil 3/5/	0.7	1.1	-	0.9	0.6	0.6	3.5	2.1	1.5	1.2	-	-	1.2
Hydro 2/	1.1	2.0	1.4	12.7	10.1	8.7	5.1	41.8	0.6	12.1	14.5	0.2	12.1
Pumped Storage	2.8	2.7	0.7	-	5.1	0.8	0.7	2.0	-	1.9	-	-	1.9
Combustion Turbine - Gas 3/	1.0	0.6	0.3	0.3	-	0.1	1.2	0.2	2.6	0.6	44.8	3.5	0.7
Combustion Turbine - Oil	2.9	19.1	5.3	13.0	11.7	9.0	3.4	3.6	0.2	7.0	12.0	7.2	7.0
Internal Combustion - Oil	0.5	0.3	0.3	1.5	0.6	1.3	0.2	0.2	0.1	0.6 4/	19.1	6.2	0.6
Internal Combustion - Gas	0.1	-	-	-	-	-	0.1	0.4	0.1	0.1	2.1	-	0.1
Geothermal	-	-	-	-	-	-	-	0.6	-	0.1	-	-	0.1
Others 6/	0.1	0.6	2.1	-	-	1.3	0.1	1.0	-	0.4	-	-	0.4

NOTES:
1/ Based on Winter generating capability, except WSCC.
2/ Adverse hydro
3/ Fuel type: Fuel expected to be burned more than 50% of the time.
4/ Includes diesel
5/ Figure includes gas and oil turbines
6/ Includes internal combustion, jet engine, fuel cell, solar, and wind power
7/ Installed capacity includes utilities and non-utilities. 1975 Data. Data not available for 1977.
8/ Includes only utilities. Data not available for the agricultural processing companies.

Table I-5

UNITED STATES
NET ELECTRICAL ENERGY GENERATED FOR 1977
BY PRINCIPAL ENERGY SOURCES
(percent of total)

Council or State	Nuclear	Coal	Oil	Gas	Hydro	Geothermal	Others
ECAR	6.4	88.8	4.7	0.1	0[1/]	0.0	0.0
ERCOT	0.0	13.3	1.9	84.5	0.3	0.0	0.0
MAAC	20.2	48.5	28.4	0.8	2.1	0.0	0.0
MAIN	23.0	71.4	4.3	0.4	0.7	0.0	0.2
MARCA	28.4	55.2	1.6	2.2	12.6	0.0	0.0
NPCC	24.1	10.5	49.6	0.2	15.6	0.0	0.0
SERC	16.4	57.2	15.6	3.0	7.8	0.0	0.0
SWPP	2.9	12.8	20.0	61.1	2.4	0.0	0.8
WSCC	5.0	24.6	22.2	12.3	34.6	0.9	0.4
Contiguous U.S.	12.4	46.4	16.9	13.7	10.3	0.2	0.1
Alaska	0.0	11.0	14.4	56.2	18.4	0.0	0.0
Hawaii	0.0	0.0	99.2	0.5	0.3	0.0	0.0
U.S. TOTAL	12.3	46.1	17.2	13.7	10.3	0.2	0.2

NOTE: 1/ < 0.02%

SOURCES: Computed based on data reported in:

1. Contiguous U.S.: NERC, "Eighth Annual Review," August, 1978.
2. Alaska and Hawaii: EEI, "Statistical Yearbook for 1977," Oct. 1978.

NPCC, SERC, and SWPP) covering all or part of 39 states. Inter-connections among the systems in the seven Councils are sufficient for the interchange of significant amounts of power in emergencies and for economic purposes [I-5].

The second network is the WSCC area covering thirteen western states (all or in part). WSCC has several sub-regional networks, numerous inter-subregional interconnections but has only minor interconnection capability with the other regional Council areas.

ERCOT is the third network. Currently interconnection between ERCOT and other Reliability Council areas is not utilized.

Table I-6 shows the circuit miles of bulk transmission lines existing as of January 1, 1978 in NERC as a whole. There are 121,079 miles of bulk alternating current transmission lines operating at voltages ranging from 230 kV through 765 kV and 2,598 miles of high-voltage direct current (HVDC) lines operating from 250 kV up to 800 kV.

The miles of transmission lines in the State of Alaska as of January 1, 1976, are 281 miles at 138 kV, 215 miles at 115 kV, 224 miles at 69 kV and 202 miles at 33 kV.

Load Resource Balance

Table I-7 shows the advance projections of the load resource balance of each Regional Electric Reliability Council, Alaska, and Hawaii, for 1978. The dependable capability planned by the utilities reporting to the Regional Reliability Councils is shown for the individual councils. The "dependable capability" referred to in this report is the total capability reported from all units controlled by the systems in the Council area, if no units are out of service.

Reserve margins shown in Table I-7 do not include the effects of inter-regional purchases and sales of capacity. The dependable capability for the whole nation was projected as approximately 539,000 MW for summer 1978 and the installed generating reserve is 30%. For winter 1978-79, the dependable capability was projected as approximately 555,000 MW and the anticipated generating reserve is 45%.

Table I-6

UNITED STATES
TRANSMISSION LINES
As of January 1, 1978
(circuit miles)

VOLTAGE (kV)	ECAR	ERCOT	MAAC	MAIN	MARCA	NPCC	SERC	SWPP	WSCC	NERC TOTAL
230	879		4,247	258	8,848	9,725	15,215	2,791	28,828	70,791
345	9,227	3,657	160	4,547	2,830	3,686	2	2,172	5,911	32,192
500	702		1,196			650	4,010	1,363	8,660	16,581
765	1,329			90		96*				1,515
HVDC										
250					465				94	559
400-450					1,195					1,195
800									844	844

*currently operated at 345-kV.

SOURCE: "Eighth Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems," National Electric Reliability Council, August, 1978.

Table I-7

UNITED STATES
PROJECTED LOAD RESOURCE BALANCE FOR 1978

Council or State	Dependable Capability 1/ MW	Peak Demand 1/ MW	Installed Reserve Margin MW	Installed Reserve Margin %
Summer 1978				
ECAR 2/	85,621	66,055	19,566	29.62
MAAC	45,532	32,713	12,819	39.19
MAIN	42,058	35,003	7,055	20.16
MARCA	22,268	18,651	3,617	19.39
NPCC	50,687	35,710	14,977	41.94
SERC	110,243	84,400	25,843	30.62
SWPP	46,487	38,946	7,541	19.36
WSCC	94,837	71,937	22,900	31.83
ERCOT	38,996	28,949	10,047	34.71
Contiguous U.S.	536,729	412,364	124,365	30.16
Alaska 4/	979	362 3/	617	170.44
Hawaii 4/	1,521	1,043 3/	478	45.83
U.S. Total	539,229	413,769	125,460	30.32
Winter 1978-79				
ECAR 2/	87,543	65,863	21,680	32.92
MAAC	48,130	28,866	19,264	66.74
MAIN	43,569	28,842	14,727	51.06
MARCA	24,152	16,879	7,273	43.09
NPCC	53,118	35,520	17,598	49.54
SERC	112,233	86,885	25,348	29.17
SWPP	47,109	27,810	19,299	69.40
WSCC	98,004	69,983	28,021	40.04
ERCOT	38,963	19,893	19,070	95.86
Contiguous U.S.	552,821	380,541	172,280	45.27
Alaska 4/	1,077	570 3/	507	88.95
Hawaii 4/	1,512	1,155 3/	366	31.69
U.S. Total	555,419	382,266	173,153	45.30

NOTES:
1/ Excludes purchases and sales of capacity. Peak demand includes interruptible load.
2/ Total of Bulk Power and Liaison Systems.
3/ Estimated from 1977 data assuming 6% growth rate.
4/ Installed Capacity.

SOURCES:
1. U.S. Department of Energy, "Electric Power Supply and Demand 1978-1987 for the Contiguous United States", DOE/ERA-0018, July, 1978.
2. U.S. Department of Interior, "Alaska Electric Power Statistics 1960-1975" (July 1976).
3. Federal Power Commission "1976 Alaska Power Survey", Volume 1.

The projections consider the scheduled initial operation of units under construction. If any units were delayed, the installed capabilities and reserve margins would have been reduced, but the tables show the relative magnitudes of systems, as if the units eventually began operation.

Inter-Regional Emergency Power Transfers

Table I-8 gives the emergency transfer capabilities between Regional Electric Reliability Councils for 1978 as reported by NERC [I-7]. The seven strongly-inter-connected Council areas, namely ECAR, SERC, MAAC, MAIN, MARCA, NPCC and SWPP, comprise essentially a single network. Interconnections among the systems are sufficient for the interchange of significant amounts of power in emergencies. In the ERCOT network, emergency transfer of power between Northern and Southern parts of Texas could be about 900 MW. The emergency transfer capability between WSCC and MARCA is 100 MW.

The Role of Hydroelectric Power in the Present Electrical System

Hydroelectric power (including pumped storage) constitutes approximately 14% of the nation's total generating capability as of January 1, 1978. It is the third largest group after coal-fired and oil-fired steam plants. However, in terms of total net electrical energy generated during 1977, hydroelectric power produced only about 10% of the nation's total energy production. It was in fifth place, following coal, oil, natural gas, and nuclear.

The function of hydroelectric power varies in different parts of the country and changes as its percentage of the national total continues to decline. In the Pacific Northwest hydro provides variously base load, intermediate load, and peak load generation. In other parts of the country, hydro is primarily used for peak loads rather than for base. With adequate storage for flow regulation over daily or longer periods, most of the nation's hydroelectric powerplants provide rapid response to changes in system loads. In some power systems hydro is the principal source of spinning reserve. Except for MARCA, ERCOT, Alaska, and Hawaii, pumped storage is currently being used throughout the country to meet peak system demands and improve the efficiency of base-load thermal plants by increasing their offpeak loading.

Table I-8

CONTIGUOUS UNITED STATES
EMERGENCY INTER-REGIONAL POWER TRANSFER CAPABILITY
(1978 - MW)

From	To ECAR
MAAC	1,250
MAIN	4,000
SERC	3,900
NPCC	2,700

From	To MAAC
ECAR	3,230
NPCC	3,300
SERC	2,700

From	To MAIN
ECAR	3,400
SWPP	1,300
MARCA	1,100
SERC	2,500

From	To MARCA
MAIN	1,050
SWPP	1,000
WSCC	100

From	To NPCC
ECAR	1,250
MAAC	1,000

From	To SWPP
MAIN	2,100
MARCA	1,150
SERC	4,000

From	To SERC
ECAR	3,850
MAAC	1,050
MAIN	3,000
SWPP	3,500

From	To ERCOT
Any Region	-0-

From	To WSCC
MARCA	100

SOURCE: "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems," National Electric Reliability Council August, 1978.

The current role of hydropower in the United States is complex and is best discussed regionally. The following chapters discuss the magnitude of existing hydroelectric power, its ownership, and the role of both conventional and pumped storage hydropower on a regional basis.

Magnitude and Ownership of Existing System

The magnitude and ownership of existing hydropower capability, both conventional and pumped storage, are summarized in Table I-9 for each Regional Reliability Council and for the States of Alaska and Hawaii. The nation's total hydroelectric generating capability is approximately 71,000 MW. About 10,000 MW of this total is in the form of pumped storage. WSCC is by far the largest hydroelectric region in the country; it has 57.5% of the total national hydroelectric capability. The remaining hydro capacity is distributed as follows: SERC (14.4%); NPCC (11.2%); ECAR (4.6%); MARCA (3.9%); SWPP (3.5%); MAAC (3.4%); and MAIN (1.2%). The amount of hydropower in ERCOT, and the States of Alaska and Hawaii is very small totaling less than 1% for all three regions.

The ownership of the hydroelectric power in the United States is made up of six distinct types:

(1) Investor-owned,
(2) Municipal
(3) State-chartered authorities
(4) Cooperative
(5) Industrial, and
(6) Federal.

As indicated on Table I-9, most of the hydro capacity in the U.S. is either Federal (42.6%) or investor-owned (33.6%). State (15.4%) and municipal (8.3%) ownership account for most of the remaining hydro capacity.

Table I-9

UNITED STATES
OWNERSHIP OF HYDROPOWER
1977

	Hydropower Capability, MW			Percent of Total					
	Conventional	Pumped Storage	Total	Investor-Owned	Municipal	State	Cooperative	Federal	By Region
ECAR	898	2,377	3,275	99.8	0.1	-	0.1	-	4.6
MAAC	947	1,286	2,233	100.0	-	-	-	-	3.2
MAIN	575	300	875	98.5	1.5	-	-	-	1.2
MARCA	2,781	-	2,781	11.9	-	4.6	0.6	82.9	3.9
NPCC	5,324	2,632	7,956	47.1	0.1	52.8	-	-	11.2
SERC	9,276	888	10,164	43.7	-	1.3	0.0	55.0	14.4
SWPP	2,218	288	2,506	3.4	2.9	16.4	-	77.6	3.5
WSCC	38,816	1,893	40,709	22.8	14.3	14.2	0.1	48.6	57.5
ERCOT	230	-	230	-	-	100.0	-	-	0.3
Contiguous U.S.1/	61,065	9,664	70,729	34.3	8.3	15.4	0.1	41.9	99.8
Alaska2/	132	-	132	8.7	17.0	-	16.0	58.3	0.2
Hawaii3/	3	-	3	100.0	-	-	-	-	0.0
U.S. Total	61,200	9,664	70,864	34.3	8.3	15.4	0.1	41.9	100.0

NOTE: The above are plants reported to DOE by Reliability Councils. In addition, small, unreported plants (primarily industrial and municipal) in MW are approximately as follows: ECAR 206, ERCOT 109, MAAC 4, MAIN 104, MARCA 173, NPCC 461, SERC 106, SWPP 84, WSCC 251. Industrial plants in Hawaii are about 16 MW. Total U.S.: 1,476 MW.

Sources:
1/ NERC, Regional Electric Reliability Council Reports to DOE, April 1978.
2/ Federal Power Commission "1976 Alaska Power Survey," 1976.
3/ U.S. Army Corps of Engineers "Hydroelectric Power Plan of Study," Sept. 1977.

References

I-1 Regional Electric Reliability Council Reports to the Department of Energy, April 1, 1978.

I-2 Federal Power Commission, "The 1976 Alaska Power Survey," 1976.

I-3 U.S. Department of the Interior, Alaska Power Administration, "Alaska Electric Power Statistics 1960-1975", Fourth Edition, July 1976.

I-4 U.S. Department of Commerce, Bureau of Economic Analysis, "1972 OBERS Projections", Regional Economic Activity in the United States, Series E Population, U.S. G.P.O., Washington, D.C. April 14, 1974.

I-5 U.S. Department of Energy, Economic Regulatory Adminstration, "Electric Power Supply and Demand 1978-1987 for the Contiguous United States", DOE/ERA-0018, June 15, 1978.

I-6 Federal Power Commission, "The 1970 National Power Survey", Part I, Washington D.C., 1970.

I-7 National Electric Reliability Council, "8th Annual Review of Overall Relaibility and Adequacy of the North American Bulk Power Systems", Princeton, New Jersey, August 1978.

I-8 U.S. Department of Energy, Federal Energy Regulatory Commission, "FPC Form No. 12", 1977.

Chapter II

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT ECAR

Introduction

This chapter describes the electric power situation within the East Central Area Reliability Council (ECAR). Regional resources and energy demand requirements are presented, as well as the load resource balance.

Regional Power System

Delineation of Region

The ECAR Region covers the east central part of the United States. Exhibit I-1 shows the ECAR boundaries and its location relative to the other councils. ECAR includes all or part of the following nine states [II-1][1/]:

Indiana	- all,
Kentucky	- major portion,
Maryland	- western and northern portions,
Michigan	- all of lower peninsula, extreme, eastern portion of upper peninsula,
Ohio	- all,
Pennsylvania	- south western portion,
Tennessee	- north eastern portion,
Virginia	- south western portion, and
West Virginia	all, except extreme eastern portion.

In the mid 1960's, the members ot the original Central Area Power Coordination Group (CAPCO) saw the need for an organization whose sole purpose would be to further increase bulk power supply reliability of the electric systems in the East Central Region. On January 14, 1967, 23 electric utilities whose systems were directly or indirectly interconnected signed the East Central Area Reliability Coordination Agreement. Subsequently three more utilities became parties to the ECAR Agreement and it now consists of 26 electric utilities (19 power systems).

These 26 bulk power system members of ECAR are shown on Exhibit II-2. The principal systems are grouped under six subregions as follows:

1/ Numbers in brackets refer to reference listed at the end of this chapter.

APS	-	Allegheny Power System,
AEP	-	American Electric Power System,
CAPCO	-	Central Area Power Coordination Group,
CCD	-	Cincinnati-Columbus-Dayton Group,
KY-IND	-	Kentucky-Indiana Group, and
MECS	-	Michigan Electric Coordinated System.

In addition to the bulk power member systems, there are electric utilities that sustain liason membership with ECAR. For the first time (1978 response [x-1]), information has been summarized and provided by the ECAR Liaison Member Systems. Twelve utilities (or group of utilities) in ECAR have been so designated by the FPC (FERC) to prepare Monthly Power Statements (FPC Form No. 12E-2) and have furnished information for Items 1, 2, and 3 [x-1]. These Liaison Member Systems are shown on Exhibit II-2. The twelve liaison members include one pool, the Michigan Municipal Cooperative Pool which comprises 8 utilities. In this study ECAR totals always include data on the bulk power members and liaison member systems and whenever possible, data for the liaison member systems are shown in the tables and exhibits. However, these systems are not included in any particular subregion. Discussions in the text are limited to only the six subregions as listed earlier.

Ownership

The bulk power membership of ECAR consists principally of investor-owned utilities. East Kentucky Power Cooperative is the sole power member of ECAR which is not investor-owned. Table II-1 summarizes the generating capability and energy demand by ownership categories for the ECAR members as shown in Exhibit II-2.

Table II-1

ECAR

OWNERSHIP OF GENERATION SOURCES
As of January 1, 1978

	Investor-Owned	Cooperative	Municipal	Total
Number of Utilities				
Members of ECAR	25	1	-	26
Liaison Members	1	7	12	20
Capability 1/				
MW	77,164	3,304	1,634	82,102
%	94.0	4.0	2.0	100.0

1/ Based on summer net generating capability.
Reference: Computed based on data from [II-1 and 2].

Transmission System

The pattern of growth for the systems in the ECAR region has led to an extensive and highly reliable transmission network operating at high voltage (61 to 161 kV) and extra high voltage (230 to 765 kV). The network provides substantial intra-system transmission as well as numerous intra-regional transmission ties. Table II-2 indicates existing transmission line mileage which services ECAR.

Table II-2

ECAR

TRANSMISSION LINES
As of January 1, 1978

Voltage (kV)	Circuit miles
230	879
345	9,227
500	702
765	1,329

Reference: [II-3]

Power Exchanges and Interties with Other Regions

As mentioned earlier, ECAR is one of nine closeknit regional groups of power supplier members of NERC. It can be seen on Exhibit I-1 that ECAR is bordered on the east by the Mid-Atlantic Area Council (MAAC), on the south by the Southeastern Electric Reliability Council (SERC), on the west by the Mid-America Interpool Network (MAIN), and on the north by the Northeast Power Coordinating Council (NPCC).

There exists interregional coordination between electric power systems within the ECAR area, as well as between systems of the various Reliability Councils. A number of utilities on the periphery of the ECAR area have interconnections and agreements with contiguous electric systems in the other coordination areas. These agreements provide for coordination of planning and operation of generation and transmission facilities to permit a variety of power transactions, increasing flexibility in system operation and contributing to economical and reliable operation. During 1977, interegional studies were performed as part of the activities related to the MAAC-ECAR-NPCC, SERC(VACAR)-ECAR-MAAC, and MAIN-ECAR-SERC(TVA) Interregional Agreements. Prior to the summer and winter peak-load season, operating studies are carried out jointly with all neighboring regions.

Regional Electric Power Demand

Socio-Economic Conditions

Table II-3 summarizes the significant demographic and economic data for the ECAR Region and its six component sub-regions. These demographic and economic data are that for the study region and subregion as approximated by the Bureau of Economic Analysis (BEA) economic areas discussed in Chapter I. The map of the region is shown in Exhibit I-2. A summary of the BEA areas approximating the sub-regions within ECAR is as follows:

Allegheny Power System	19,65,66;
American Electric Power System	20,51,52,64,76;
Central Area Power Coordination Group	67,68,70;
Cincinnati-Columbus-Dayton Group	62,63,69;
Kentucky-Indiana	53,54,55,56,59,60, 61,75, and
Michigan Electric Coordinated System	71,73,74.

The population of the ECAR region has been gradually increasing since 1950 at the average annual rate of 1.1 percent, slightly slower than the U.S. population growth rate of 1.5 percent. In 1950 the ECAR population was 17.8 percent of the national total, but only 16.5 percent of the national total in 1970. In 1970, the Michigan Electric Coordinated System with a population of 8,200,000, (about 25 percent of the ECAR population) was the largest single ECAR subregion in terms of population. In addtion, the Michigan subregion also had a high population growth rate of 1.7 percent between 1950 and 1970. The Central Area Power Coordination Group and the Kentucky-Indiana sub-region each contained about 18 percent of the 1970 ECAR region population.

The industrial sectors of manufacturing and trade represented important sources of earnings and income in the ECAR region. Together the manufacturing and trade sectors produced about 55 percent of the region's earnings. However, ECAR's manufacturing and trade earnings were not growing as fast as national totals, representing shrinking shares of the national market. The mining industry is of particular interest, since it represented a large share of the national total earnings. Earnings in the ECAR based mining industry represented 25 percent of the national mining industry earnings during 1970. Overall, the ECAR Region total earnings grew at 3.5 percent annually between 1950 and 1970, but ECAR's share of national total earnings was decreasing.

The Michigan and the Central Area Power Coordination subregions produced the largest share of the ECAR region's manufacturing and trade earnings. The Cincinnati-Columbus-Dayton subregion was also dependent upon manufacturing and trade as an important source of income. In addition to the manufacturing and trade sectors, the government sector supplied a significant portion of the earnings in the Kentucky-Indiana subregion. Mining was important in the Alleghany and American Electric Power subregions. Together, they produced 74 percent of the mining earnings originating in the ECAR region, or about 18 percent of the national mining total.

Table II-3 also shows 1970 per capita income and per capita income relative to the United States for ECAR and the subregions. Alleghenv Power, American Electric Power, and the Kentucky-Indiana subregions had the highest average annual growth rates of 2.6, 3.0, and 2.9 percent respectively for the period between 1950 and 1970. However, the same power system areas had the lowest 1970 per capita income with respect to the Nation. The Cincinnati-Columbus-Dayton Group, Central Area Power and the Michigan Electric subregions each had per capita income higher than the U.S. and ECAR averages, but were experiencing average growth rates less than the ECAR average.

Peak Demand

Exhibit II-3 gives the historical annual energy, peak demand, and load factor of ECAR. Also included in Exhibit II-3 are annual growth rates and average compounded annual growth rates for 5-year periods of annual energy and peak load. The peak load in ECAR increased at an average annual growth rate of about 6.7% over the 1965-1970 period from 31 GW in 1965 to 43 GW in 1970. It continued to grow at a high annual growth rate until the 1973 oil embargo. As a result of the embargo, the average annual growth rate over the 5-year period from 1970 to 1975 dropped to about 5%. The peak load in 1977 was 62.3 GW.

Regional annual energy, peak demand, and load factor during 1977 for each subregion and for ECAR are shown in Table II-4. ECAR has both summer and winter peaking systems.

Table II-3

ECAR

ECONOMIC INDICATORS
1970

Sector Earnings[1] (Million $)	APS	AEP	CAPCO	CCD	MECS	KY-IND	ECAR
Agriculture	115	269	246	221	286	669	1,805
Mining	452	586	83	15	42	232	1,410
Construction	734	803	1,098	556	1,360	935	5,486
Manufacturing	4,040	4,267	7,782	3,722	10,718	5,552	36,080
Transportation Utilities	892	959	1,194	575	1,313	996	5,929
Trade	1,668	1,899	2,818	1,425	3,782	2,389	13,982
Finance	394	479	638	356	913	647	3,427
Services	1,607	1,548	2,359	1,197	3,204	1,815	11,730
Government	1,299	1,733	1,765	1,370	3,295	2,323	11,785
Total Earnings (Million $) 1/	11,201	12,542	17,982	9,437	24,914	15,557	91,634
Population (Thousands)	4,461	5,426	6,102	3,336	8,189	6,026	33,539
Per Capita Income ($) 1/	3,215	2,887	3,623	3,498	3,718	3,153	3,376
Per Capita Income Relative to the U.S.	0.925	0.831	1.042	1.006	1.070	0.907	0.971

1/ Constant 1967 dollars

Reference: [II-4]

Note: Because of rounding, some parts do not sum exactly to totals.
Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietors' income and other labor income), property income and transfer payments, less personal contributions for social insurance.

Table II-4

ECAR

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

	Annual Energy GWh	Peak[1/] Demand MW	Month of Peak Demand	Annual Load Factor,%
Allegheny Power System	30,470	5,031	January	69.1
American Electric Power System	72,052	12,214	January	67.4
Central Area Power Coordination Group	63,322	11,164	July	64.7
Cincinnati-Columbus-Dayton Group	34,146	6,727	July	57.9
Kentucky-Indiana Group	81,347	13,906	July	66.8
Michigan Electric Coordinated System	65,874	11,923	July	63.1
Liaison Members	18,315	3,224	January	64.8
ECAR	365,526	62,306	July	67.0

Reference: [II-1]

1/ Coincidental Peak.

Energy Demand

Annual demand for electric energy during the period 1965-1977 for ECAR is shown in Exhibit II-3. The annual demand for electric energy in ECAR increased from about 180,500 GWh in 1965 to 262,000 GWh in 1970. This corresponds to an average annual growth rate of about 7.7% over the 1965 level. The demand continued to rise at a high growth rate and reached a level of about 325,000 GWh in 1973 (7.4% average annual growth rate over the 1970-1973 period). After the 1973 oil embargo the energy demand in ECAR decreased in 1974 and 1975. In 1976 energy demand in ECAR increased to 327,200 GWh, only slightly higher than the 1973 level. In 1977, the energy demand rose to 365,526 GWh, an annual increase of 11.7% from 1976.

Table II-4 gives the annual energy demand for each subregion and for ECAR. Annual growth rate of electric energy consumption between 1972 and 1976 by consumer category is shown in Exhibit II-4. These categories are residential, commercial, and industrial. The growth rates of the total energy consumption are also given. Following the 1973 oil embargo, the growth rates decreased. But since 1976, ECAR and most of its constituent members have registered current consumption growth rates which exceed pre-embargo levels.

Table II-5 gives the 1976 energy consumption by consumer categories for some of the power pools.

Table II-5

ECAR
ENERGY CONSUMPTION BY CONSUMER CATEGORIES
1976 - (Percent of Total)

Power Pool	Rural and Residential	Commercial	Industrial	Others	Total
AEP	24.6	12.5	45.9	16.0	100.0
APS	28.2	15.0	52.8	3.0	100.0
CAPCO	25.1	22.7	47.0	5.2	100.0
CCD	34.8	23.2	31.1	9.9	100.0

Source: Reports to the Ohio Power Siting Commission, April 1977.

Load Characteristics

Exhibit II-3 lists annual load factors which occurred in ECAR during the period 1965-1977. The average annual load factor for ECAR during the previous decade is 69 percent. Table II-4 shows annual load factors for each subregion and for ECAR based on 1977 energy levels. Annual load factors for the sub-regions of ECAR ranged between 58-69 percent for the year 1977. For the same period, the annual load factor for ECAR is 67.0.

Table II-6 gives the monthly energy and peak demand during the 12 months of 1977 for each bulk power supplier of ECAR.

Exhibit II-5 shows the weekly load factors for the first week of April, August, and December 1977 for the bulk power members of ECAR. The magnitude of the weekly peak load demand and the date of its occurrence are also given [II-5]. Weekly load curves and load duration curves for seven representative utilities in ECAR are given in Exhibit II-6. The December, April and August load duration curves for all of these utilities are very similar. For all systems the August load duration lies above the other two months. However, despite the similarities a block of power representing some fixed percentage of load below the annual peak requires greatly differing amounts of energy from day to day and seasonally.

Regional Electric Power Supply

Existing Generating Facilities

Exhibit II-7 gives generating capability by types of plants for ECAR and each subregion. Table II-7 summarizes total summer and winter generating capability and generation mix on the basis of plant category for ECAR and each subregion. Most of the generating facilities within ECAR utilize coal to drive steam turbines. Nuclear and oil-fired steam plants presently provide only about 10.4 percent of generating capability. Pumped storage plants, conventional hydroelectric facilities, combustion turbine plants, and other types of plants make up the rest of generating capability.

Nuclear power plants are operated by American Electric Power System, Central Area Power Coordination Group, and

Table II-6

ECAR
MONTHLY ENERGY AND PEAK DEMAND
1977

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Allegheny Power System												
Peak Hour Demand - MW	5,031	4,634	4,434	4,301	4,119	4,139	4,524	4,539	4,478	4,296	4,549	4,883
Net Energy - GWh	2,990	2,496	2,583	2,355	2,405	2,531	2,468	2,492	2,337	2,465	2,537	2,811
Load Factor - %	79.9	80.2	78.3	76.0	78.5	84.9	73.3	73.8	72.5	77.1	75.0	77.4
American Electric Power System												
Peak Hour Demand - MW	12,214	11,678	10,522	9,952	10,015	10,165	11,232	10,538	10,684	10,287	11,121	11,811
Net Energy - GWh	7,231	6,019	6,039	5,408	5,621	5,634	5,911	5,907	5,583	5,877	6,133	6,789
Load Factor - %	79.6	76.7	77.1	75.5	75.4	77.0	70.7	75.3	72.6	76.8	74.1	77.3
Central Area Power Coordination Group												
Peak Hour Demand-MW	9,824	9,283	8,981	8,952	10,013	9,991	11,164	10,438	10,809	8,900	9,358	9,933
Net Energy - GWh	5,677	4,956	5,295	4,912	5,212	5,169	5,562	5,522	5,151	5,154	5,174	5,538
Load Factor - %	77.7	79.4	79.2	76.2	70.0	71.9	67.0	71.1	66.2	77.8	74.3	74.9
Cincinnati-Colombus-Dayton Group												
Peak Hour Demand - MW	5,508	5,381	4,864	4,766	5,706	5,777	6,727	6,222	6,439	4,737	5,198	6,139
Net Energy - GWH	3,271	2,664	2,676	2,455	2,753	2,714	3,261	3,062	2,755	2,622	2,746	3,169
Load Factor - %	79.8	73.7	73.9	71.5	64.8	65.2	65.2	66.1	59.4	74.4	71.0	69.4
Kentucky-Indiana Group												
Peak Hour Demand - MW	12,817	12,095	11,105	10,923	12,374	12,522	13,906	13,401	13,449	10,836	11,797	12,922
Net Energy - GWh	7,650	6,346	6,504	6,062	6,596	6,610	7,516	7,181	6,534	6,485	6,557	7,306
Load Factor - %	80.2	78.1	78.7	77.1	71.6	73.3	72.6	72.0	67.5	80.4	74.7	76.0
Michigan Electric Coordinated System												
Peak Hour Demand - MW	10,235	9,882	9,265	9,164	10,554	10,888	11,923	10,674	10,437	9,359	10,138	10,278
Net Energy - GWh	5,939	5,133	5,459	5,003	5,414	5,398	5,921	5,754	5,335	5,407	5,438	5,673
Load Factor - %	78.0	77.3	79.2	75.8	68.9	68.9	66.7	72.5	71.0	77.7	72.1	74.2
Liaison Members												
Peak Hour Demand-MW	3,244	2,982	2,698	2,604	2,584	2,579	2,830	2,694	2,684	2,493	2,885	3,170
Net Energy - GWh	1,881	1,531	1,518	1,372	1,418	1,402	1,539	1,498	1,413	1,467	1,527	1,749
Load Factor - %	77.9	76.4	75.6	73.2	73.8	75.5	73.1	74.7	73.1	79.1	71.1	74.2
ECAR Region												
Peak Hour Demand - MW	58,873	55,935	51,869	50,662	55,365	56,061	62,306	58,506	58,980	50,908	55,046	59,136
Net Energy - GWh	34,639	29,145	30,074	27,567	29,419	29,356	32,178	31,416	29,108	29,477	30,112	33,035
Load Factor - %	79.1	77.5	77.9	75.6	71.4	72.7	69.4	72.2	68.5	77.8	73.5	75.1

Reference: [II-1]

Table II-7

ECAR
GENERATING CAPABILITY
1977

	ECAR	APS	AEP	CAPCO	CCD	KY-IND	MECS	Liaison Members
Summer Capability	82,102	6,203	16,311	14,575	8,149	17,387	15,348	4,129
Winter Capability	83,886	6,429	16,561	14,894	8,456	17,617	15,714	4,215
Generation Mix in Winter (Percentage)								
Nuclear	3.7	-	6.3	8.2	-	-	5.0	-
Steam Turbine								
Gas	0.1	-	-	-	-	0.4	0.1	0.2
Coal	80.3	91.3	88.0	77.4	82.5	92.3	53.8	88.3
Oil	6.7	7.6	1.4	5.2	3.3	2.8	20.7	2.5
Combined Cycle	0.7	-	-	3.8	-	-	-	0.6
Hydro	1.1	1.0	3.4	-	-	0.7	0.9	0.8
Pumped Storage	2.8	-	0.8	2.4	-	-	11.9	-
Combustion Turbine								
Gas	1.0	-	-	-	0.9	0.7	4.0	-
Oil	2.9	-	0.1	2.8	10.8	2.9	2.6	4.7
Internal Combustion								
Oil	0.5	-	-	0.2	1.2	0.2	1.0	1.6
Jet Engine-Kerosene	0.1	-	-	-	1.3	-	-	1.3
Others	-	0.1	-	-	-	-	-	-
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Reference: [II-1]

Michigan Electric Coordinated System. American Electric Power System and the Kentucky-Indiana Group supply nearly half of ECAR's coal derived electricity. Nearly half of ECAR's hydroelectric plants are operated by the American Electric Power System.

Current Role of Hydropower

Hydropower, including conventional hydroelectric and pumped storage is 4.1% of the ECAR system generating capability as compared to about 12 percent for the 1977 national average. The majority of hydropower facilities are pumped storage plants. There are currently three pumped storage projects in operation, (1) Smith Mountain of Appalachian Power Company in the AEP System, with a generating capability of 460 MW (of which 320 MW is conventional hydro), (2) Seneca of Cleveland Electric Illuminating Company in the CAPCO System, with a generating capability of 365 MW (current share in ECAR), and (3) Ludington of Consumers Power Company and Detroit Edison Company in the Michigan Electric Coordinated System, with a generating capability of 1,872 MW. These combined represent about 3.1 percent of the ECAR System generating capability. This amount is small compared to what the system can readily absorb if pumped storage sites are available and can be developed.

Conventional hydroelectric plants represent 1.1 percent of the ECAR System generating capability. The role of conventional hydropower in ECAR is therefore relatively small. Most of the plants serve as intermediate or peaking generating facilities, except in high flow months when some operate on base. Conventional hydro operated for peaking in various degrees includes Markland, Claytor, Smith Mountain, Lake Lynn, and several small AEP plants. In addition to their intermediate or peaking role, hydroelectric powerplants with adequate storage for flow regulation over daily or longer periods provide a rapid response type generation to the systems in which they operate. Hydro provides good sources of spinning reserve. The pumped storage projects are of great importance to the system as they increase minimum loads during offpeak hours, improving the efficiency of base-load thermal units.

Table II-8 lists hydropower plants presently operating within ECAR. All hydropower plants are investor-owned except about 4 MW which are owned by cooperative (2MW) and Municipal (2MW) utilities.

Table II-8

ECAR

HYDROPOWER CAPABILITY 1/
As of January 1, 1978

System	Conventional Hydro Plant Name	Conventional Hydro Capability MW	Pumped Storage Plant Name	Pumped Storage Capability MW
Allegheny Power System	Lake Lynn	52		
	Miscellaneous Hydro	10		
American Electric Power System	Smith Mountain	320	Smith Mountain	140
	Small Hydro	107		
	Claytor	76		
	Leesville	40		
Central Area Power Coordination Group	-		Seneca	365 2/
Kentucky-Indiana Group	Markland	55		
	Dix Dam	24		
	Ohio Falls	35		
	Norway	4		
	Oakdale	6		
Michigan Electric Coordinated System	Hydro	134	Ludington	1,872
Liaison Members	Miscellaneous Hydro	35		-
Total		898		2,377

1/ Winter generating capability.
2/ This is the current share in ECAR. 76 MW are allocated to MAAC.

Note: The above are plants reported to the DOE by ECAR. All of the above plants are investor-owned. In addition, ownership of small, unreported plants (primarily industrial and investor-owned) are approximately as follows: Industrial 110 MW, Public (non-federal) 9 MW, Federal 18 MW, Investor-owned 68 MW, and Cooperative 1 MW; Total 206 MW.

Reference: [II-2]

Load Resource Analysis

Table II-9 shows net capability, total resources, and peak hour demand including interruptible demand for ECAR and each subregion as projected for 1978 in the ECAR report [II-1]. Scheduled imports and exports have been respectively added and subtracted to obtain total resources. The margin is the difference between total resources and peak demand minus interruptible demand. The margin percentages of demand and resources are also shown.

Within ECAR, margin or surplus energy above demand average 32%. The margin is usually higher in winter than in summer. The Central Area Power Coordination Group and the Cincinnati-Colomubus-Dayton Group have reserves which exceed 40% of the demand requirements while the American Electric Power System has reserves which only average 23% of the demand. The current high reserve margin in ECAR is due to a recent decrease in load growth as compared to projection. The margin is expected to drop in subsequent years.

For 1978, ECAR is a net exporter of 1,183 MW in summer, and 79 MW in winter. In addition, ECAR has interchange of emergency, short term, diversity, and economy power with adjoining systems. Current emergency transfer capability between ECAR and surrounding reliability councils are shown in Table II-10.

Table II-9

ECAR
RESOURCES, DEMAND AND MARGIN
PROJECTED FOR 1978

Resources in MW	ECAR		APS		AEP		CAPCO		CCD		KY-IND		MECS		Liaison Members	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Net Capability	85,621	87,543	6,223	6,428	17,411	17,661	15,117	15,438	9,024	9,561	18,515	18,637	15,277	15,655	4,054	4,163
Scheduled Imports	412	713	0	300	434	177	0	0	20(	200	1,477	1,430	620	20	202	203
Scheduled Exports	1,595	792	350	50	1,700	600	0	C	10	11	1,129	888	624	624	25	28
Total Resources	84,438	87,464	5,873	6,678	16,145	17,238	15,117	15,438	9,214	9,750	18,863	19,179	15,273	15,051	4,231	4,338
Inoperable Capability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Operable Resources	84,438	87,464	5,873	6,678	16,145	17,238	15,117	15,438	9,214	9,750	18,863	19,179	15,273	15,051	4,231	4,338
Demand In MW																
Peak Hour Demand	66,055	65,863	4,785	5,545	12,318	13,874	11,828	10,968	7,182	6,564	14,952	14,341	11,989	11,028	3,001	3,543
Interruptible Demand	622	640	51	59	335	335	190	190	10	20	36	36	0	0	0	0
Demand Requirements	65,433	65,223	4,734	5,486	11,983	13,539	11,638	10,778	7,172	6,544	14,916	14,305	11,989	11,028	3,001	3,543
Margin																
Margin, MW	19,005	22,241	1,139	1,192	4,162	3,699	3,479	4,660	2,042	3,206	3,947	4,874	3,284	4,023	1,230	795
Percent of Demand Requirements	29.0	34.1	24.1	21.7	34.7	27.3	29.9	43.2	28.5	49.0	26.5	34.1	27.4	36.5	41.0	22.4
Percent of Operable Resources	22.5	25.4	19.4	17.8	25.8	21.5	23.0	30.2	22.2	32.9	18.5	25.4	21.5	26.7	29.1	18.3

Reference: [II-2]

Table II-10

ECAR
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCIL
Projected for 1978 - MW

From:		To:
ECAR	3,000-3,250	MAAC
MAAC	1,250	ECAR
ECAR	3,400	MAIN
MAIN	4,000	ECAR
ECAR	1,250	NPCC
NPCC	1,600-2,700	ECAR
ECAR	2,500	SERC (TVA)
SERC (TVA)	1,500	ECAR
ECAR	1,350	SERC (VACAR)
SERC (VACAR)	2,400	ECAR

Reference: [II-3]

REFERENCES

II-1 ECAR "Coordinated Regional Bulk Power Supply Programs," Volume 1-2, FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

II-2 U.S. Department of Energy, "Principal Electric Facilities," DOE/EIA-0057/1-11, 1978.

II-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," August 1978.

II-4 U.S. Department of Commerce, Bureau of Economic Analysis, "1972 OBERS Projections," Regional Economic Activity in the United States, Series E Population, U.S. G.P.O, Washington, D.C. April 14, 1974.

II-5 Federal Power Commission, "FPC Form 12," Washington, D.C., 1977.

Chapter III

MID ATLANTIC AREA COUNCIL
MAAC

Introduction

This chapter describes regional power systems of the Mid-Atlantic Area Council (MAAC). Regional electric power demand and supply, and the load resource balance are presented.

Regional Power System

Delineation of the Region

The MAAC area covers approximately 48,700 square miles. It includes all or part of the states listed below:

all of Delaware and the District of Columbia
97% of New Jersey
75% of Pennsylvania
60% of Maryland
1% of Virginia

Approximately twenty million people were served by the member systems in MAAC in 1977. [III-1][1/]. MAAC's geographic boundaries and its position in relation to the other councils is shown on Exhibit I-1.

Ownership

The principal companies composing the Mid-Atlantic Area Council are coordinated in the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Exhibit III-2 lists the 11 investor-owned members of PJM. The exhibit also states the associate members which represent Maryland and New Jersey Municipals as well as Pennsylvania and New Jersey Cooperatives.

1/ Numbers in brackets refer to references listed at the end of this chapter.

Operation of the MAAC region is coordinated from the P.J.M. Control Center located near Valley-Forge, Pennsylvania.

Transmission System

Table III-1 indicates the existing mileage of the bulk transmission lines of the MAAC Region.

Table III-1

MAAC - TRANSMISSION LINES
As of January 1, 1978

Voltage (kV)	Circuit Miles
230	4,247
345	160
500	1,196

Reference: [III-3]

As discussed in Chapter I, MAAC has a transmission interconnection with the adjacent Reliability Council Regions.

Power Exchanges and Interties between Regions

MAAC and PJM study and coordinate nearly every aspect of intracouncil operation and planning affecting overall reliability and adequacy. Studies of regional and interregional operation are made prior to any peak period. Additionally, the following interregional studies have been conducted:

- VACAR-ECAR-MAAC 1980 Interregional System Performance Study - January 1976.
- MAAC-ECAR-NPCC 1980 Interregional System Performance Study - February 1977.
- MAAC-ECAR-NPCC 1982 Interregional System Performance Study - August 1977.

MAAC regularly participates with neighboring councils (the Joint Interarea Review Committees) to discuss the coordination of future plans, to review actual operations, and to provide guidance for future studies.

Regional Electric Power Demand

Socio-Economic Conditions

Table III-2 summarizes the significant demographic and economic data for the MAAC region. These demographic and economic data for the study region are for economic areas corresponding reasonably closely but not identically with MAAC boundaries, as discussed in Chapter I. The map of the MAAC Region is shown in Exhibit I-1. The list of BEA areas comprising MAAC is shown in Exhibit I-3.

The population of MAAC has been increasing at the average annual rate of 1.2 percent between 1950 and 1970. The 1970 MAAC population represented 9.7 percent of the national total. Historically, the population of MAAC has grown slightly slower than the national population.

The total earnings originating in MAAC have been growing at about 3.6 percent annually, although the MAAC share of national earnings has decreased from 11.6 percent in 1950 to 10.6 percent in 1970. In terms of total dollars earned, the manufacturing and trade sectors have respectively contributed 31 and 16 percent of the MAAC total earnings in 1970. The government and service sectors also produce significant portions of MAAC earnings.

With respect to national markets, the manufacturing and construction industries contributed 11.7 and 10.3 percent to respective national sector 1970 earnings totals. The agriculture and mining industries provided the smallest earnings value expressed as a percentage of national sector totals.

Per capita income in MAAC has been increasing at the average annual rate of 2.5 percent between 1950 and 1970. The MAAC growth rate of per capita income is less than that of the Nation. In 1950, the MAAC Region per capita income was 15 percent above the national average. In 1970, the margin of MAAC per capita income above the national average decreased to 11 percent.

Table III-2

MAAC
ECONOMIC INDICATORS
1970

Sector Earnings (Million $) 1/

Agriculture	699
Mining	161
Construction	3,555
Manufacturing	18,235
Transportation Utilities	4,523
Trade	9,838
Finance	3,668
Services	9,702
Government	9,276
Total Earnings (Million $) 1/	59,657
Total Population (Thousands)	19,737
Per Capita Income ($) 1/	3,850
Per Capita Income Relative to U.S.	1.107

1/ Constant 1967 dollars

Note: MAAC Region is approximated by BEA areas 10, 11, 13, a portion of 14, 15, 16, and 17.

Reference: [III-5]

Peak Demand

Exhibit III-3 gives the historical annual energy, peak demand, and load factor of MAAC for the years 1960, 1965, 1970, and 1973 through 1977. Also included in Exhibit III-3 are annual growth rates of annual energy and peak demand.

The peak hour demand increased by 9.7% from 1976 to 1977, compared to an annual increase of 1.8% for 1975-1976, 2.3% for 1974-1975, and a decrease of 7.8% for 1973-1974. This corresponds to an average annual growth rate of 1.5% over the 1973-1977 period. In 1977, the highest peak hour demand was 32,306 MW, in July. The winter peak was 27,199 MW in January.

Energy Demand

The annual demand for energy increased by 3.5% from 1976 to 1977, compared to an annual increase of 3.4% for 1975- 1976, 0.4% for 1974-1975, and a decrease of 0.9% for 1973-1974. This corresponds to an average annual growth rate of 1.6% over the 1973-1977 period. In 1977, the annual net energy was 164,135 GWh.

Exhibit III-4 shows the annual growth rates of energy consumption by consumer categories for the major electric systems in MAAC for the years 1971 to 1977. These categories are residential, commercial, and industrial. Table III-3 states the 1977 energy consumption by consumer categories for some representative utilities of MAAC.

Load Characteristics

Exhibit III-3 states the load factor of MAAC for the year 1960, 1965, 1970, and 1973 through 1977. In 1977, the annual load factor was 58.0%. Exhibit III-5 gives the weekly load factors during the first week of April, August, and December 1977, for the Pennsylvania-New Jersey-Maryland Interconnection. Weekly load and load duration curves for PJM are shown in Exhibit III-6. The load duration curves appear generally very similar to those of ECAR utilities whereas the load variations each day as shown by the load curves generally are larger in PJM than in ECAR.

Table III-4 gives the energy, peak demand and load factor for the 12 months of 1977.

Table III-3

MAAC
ENERGY CONSUMPTION BY CONSUMER CATEGORIES
1977 - (Percent of Total)

	Residential	Commercial	Industrial	Sale For Resale	Others	Total
Philadelphia Electric Co.	29.8	10.4	54.8	-	5.0	100.0
General Public Utilities	34.5	22.9	36.4	-	6.2	100.0
Baltimore Gas & Electric Co.	33.8	18.8	47.4	-	-	100.0
Potomac Electric Power Co.	24.2	42.5	25.8	6.4	1.1	100.0
Pennsylvania Power & Light Company	35.6	24.6	36.3	-	3.5	100.0
Delmarva Power & Light Co.	27.9	21.6	33.0	17.5	-	100.0
Atlantic City Electric Co.	44.6	29.7	24.5	-	1.2	100.0
Public Service Electric & Gas Company	27.3	34.3	37.4	0.1	0.9	100.0

Sources: 1977 Annual Reports of the above listed utilities.

Table III-4

MAAC[1/]

MONTHLY ENERGY, PEAK DEMAND & LOAD FACTOR
1977

Month	Peak Hour Demand-MW	Monthly Energy-GWh	Monthly Load Factor-%
January	27,199	15,616	77.2
February	25,309	12,841	75.5
March	23,123	13,140	76.5
April	22,248	12,080	75.6
May	25,136	12,773	68.4
June	26,843	13,183	68.3
July	32,306	15,195	63.2
August	29,894	15,321	68.9
September	30,376	13,345	60.9
October	23,106	12,726	74.0
November	24,958	13,129	73.2
December	26,723	14,786	74.4
1977	32,306	164,135	58.0

Reference: [III-2]

1/ Includes PJM and the associates.

Regional Electric Power Supply

Existing Generating Facilities

Exhibit III-7 shows the winter generating capability by type of plants for the MAAC members, the 1977 total being 46,783 MW. Table III-5 shows the 1977 winter generating capability by type of plants. The 1977 summer generating capability is 44,253 MW.

MAAC relies on coal and oil to drive steam turbines for 60.2% of the 1977 total generating capability. Nuclear unit provide 13.4% of the total. Conventional hydroelectric and pumped storage comprise only 4.7% of the total capability.

Combustion turbines are relied upon to a large degree for peaking service.

Table III-5

MAAC
GENERATING CAPABILITY BY TYPE OF PLANTS 1/
1977

	MW	%
Nuclear	6,287	13.4
Steam Turbine		
Coal	15,527	33.2
Oil	12,623	27.0
Combined Cycle	507	1.1
Hydroelectric	947	2.0
Pumped Storage	1,286	2.7
Combustion Turbine		
Gas	275	0.6
Oil	8,921	19.1
Internal Combustion		
Oil	146	0.3
Jet Engine	264	0.6
TOTAL	46,783	100.0

Reference: [III-2]

1/ Winter Capability.

Current Role of Hydropower

Hydropower including conventional hydroelectric and pumped storage has a total capability of 2,233 MW. Pumped storage facilities exceed conventional hydroelectric capability. Table III-6 lists hydroelectric plants within MAAC in 1977. These plants are investor-owned.

The 1,286 MW of pumped storage capability in MAAC provides system peaking generation. The required off-peak pumping energy improves the off-peak operation of thermal units. The conventional hydroelectric plants predominately operate as run-of-river projects utilizing the

Table III-6

MAAC
HYDROPOWER CAPABILITY 1/
1977

System	Conventional Hydro Plant Name	Conventional Hydro Capability MW	Pumped Storage Plant Name	Pumped Storage Capability MW
Public Service Electric & Gas	-	-	Yards Creek	165
Philadelphia Electric Company	Conowingo	512	Muddy Run	880
Pennsylvania Power & Light Company	Holtwood	102		
	Wallenpaupack	44		
	Safe Harbor	76		
Baltimore Gas & Electric Company	Safe Harbor	152		
General Public Utilities	Deep Creek	19	Seneca	76 2/
	Piney	28	Yards Creek	165
	York Haven	14		
TOTAL		947		1,286

1/ Winter Generating Capability

2/ This is the current share in MAAC. 365 MW are allocated to ECAR.

Reference: [III-2]

The above are plants reported to MAAC by the utilities. In addition, small unreported plants in MAAC are approximately as follows: 1.5 MW Industrial, 2.5 MW Public (non-federal), 4 MW Total.

limited pondage in their reservoirs to regulate the natural runoff on a daily and weekly basis. The hydro plants, such as the Safe Habor, Holtwood, Conowingo, and Muddy Run, which belong to the Pennsylvania-New Jersey-Maryland (PJM) interconnected system, provide peaking generation within the system thereby increasing system flexibility, efficiency and economy of operation.

Load Resource Analysis

Table III-7 lists a detailed description of the capability, demand, and margin of the MAAC area projected for 1978. Margin capacity above demand averages 39%. This high reserve margin is due to a recent decrease in load growth as compared to earlier projections. The margin is expected to be reduced in subsequent years.

In 1978, MAAC was projected to have a net import of 180 MW. In addition, MAAC has interchange of emergency, short term, diversity and economy power and energy with adjoining systems. Current emergency transfer capabilities between MAAC and surrounding reliability councils are shown in Table III-8.

Table III-7

MAAC
RESOURCES, DEMAND & MARGIN
PROJECTED FOR 1978

	Summer MW	Winter MW
RESOURCES		
Net Dependable Capability	45,532	48,130
All Scheduled Imports	180	180
All Scheduled Exports	0	0
Total Resources	45,712	48,310
Inoperable Capability	457	484
Operable Resources	45,255	47,826
DEMAND		
Peak Hour Demand	32,713	28,866
Interruptible Demand	0	0
Demand Requirements	32,713	28,866
MARGIN		
Margin	12,542	18,960
Scheduled Outage	1,700	5,550
Adjusted Margin	10,842	13,410
Percentage of Demand Requirement	33.1%	46.5%
Percentage of Operable Resources	23.9%	28.0%

Reference: [III-2]

Table III-8
MAAC
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS
1978

From:		To:
MAAC	1,250	ECAR
ECAR	3,230	MAAC
MAAC	1,000	NPCC
NPCC	3,300	MAAC
MAAC	1,050	SERC
SERC	2,700	MAAC

Reference: [III-3]

REFERENCES

III-1 National Electric Reliability Council, "1977 National Report," Prinction, N.J., March, 1978.

III-2 MAAC, "Systems plans report," FERC(FPC) Order 383-4, Docket R-362, April 1, 1978.

III-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," August 1978.

III-4 Federal Power Commission, "FPC Form 12," Washington, D.C. 1977.

III-5 U.S. Water Resources council, "1972, OBERS Projections," Volume 1-2, Washington, D.C., April 1974.

Chapter IV

MID-AMERICA INTERPOOL NETWORK
MAIN

Introduction

This chapter describes the power systems which are bulk power suppliers in the Mid-America Interpool Network (MAIN). An analysis of regional electric power demand and supply is presented as well as a load resource balance.

Regional Power System

The Mid-America Interpool Network was formally organized in November 3, 1964 to improve the reliability of electric bulk power supply in the Mid-West. MAIN offers membership to any power supplier who has an interconnection of 115 kV or above with a regular member and whose operations have a significant effect on the relability of the councils' interconnected system [IV-1][1/]. The MAIN region includes the state of Illinois, the eastern halves of Missouri and Wisconsin and the upper peninsula of Michigan (as of 1977).

Deliniation of Region

The members of MAIN are grouped into three geographical subregions. These three subregions are (1) Commonwealth Edison, which includes the northern portion of Illinois, (2) the Illinois-Missouri subregion which covers the remaining portion of Illinois and the portion of Missouri, and (3) the Wisconsin-Upper Michigan System, which covers Wisconsin and the upper peninsula of Michigan. The boundaries of MAIN are shown in Exhibit I-1.

Ownership

MAIN presently consists of 13 regular members and 4 assoicate members. The members include 10 investor-owned utilities, 1 municipal utility, and 2 cooperatives. The associate members include 3 municipal systems and 1 cooperative. In addition there are 2 municipal utilities reporting to MAIN who are non-members. Table IV-1 shows the number of reporting utilities in each category of ownership and the respective capability in MW as well as percent of total for

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1/ Numbers in brackets refer to the list of references at the end of the chapter.

Table IV-1

MAIN

OWNERSHIP OF GENERATION SOURCES 1/
AS OF JANUARY 1, 1978

	Investor-Owned	Cooperative	Municipal	Total
MAIN				
Number of Utilities				
Members	10	2	1	13
Associates	-	1	3	4
Non-Members	-	-	2	2
Total	10	3	6	19
Capability				
MW	37,696	1,994	688	40,378
%	93.4	4.9	1.7	100.0
Commonwealth Edison Company				
Number of Utilities				
Members	1	-	-	1
Capability				
MW	16,329	-	-	16,329
%	100.0	-	-	100.0
Illinois-Missouri				
Number of Utilities				
Members	4	2	1	7
Associates	-	1	-	1
Non-Members	-	-	1	1
Total	4	3	2	9
Capability				
MW	14,129	1,994	463	16,586
%	85.2	12.0	2.8	100.0
Wisconsin Upper Michigan System				
Number of Utilities				
Members	5	-	-	5
Associates	-	-	3	3
Non-Members	-	-	1	1
Total	5	-	4	9
Capability				
MW	7,238	-	225	7,463
%	97.0	-	3.0	100.0

1/ Based on summer capability.
Reference [IV-1]

the MAIN region and the three subregions. Table IV-1 shows that MAIN has 93.5% of the winter net generating capability represented by the investor-owned utilities, 4.8% by the cooperatives and 1.7% by the municipal systems. These utility systems provide essentially all of the electric service in the MAIN region. The MAIN regular members, associate members and reporting non-members are listed in Exhibit IV-2.

Transmission Systems

As of Janaury 1, 1978 the MAIN interconnected power system comprised 4,895 miles of transmission lines at 230 kV and higher (see Table IV-2).

Table IV-2

MAIN

TRANSMISSION LINES

As of Janaury 1, 1978

Voltage (kV)	Transmission Lines (Circuit Miles)
Alternating Current	
230	258
345	4,547
500	-
765	90

Reference [IV-2]

Power Exchange and Interties between Regions

MAIN, as one of the nine regional NERC members, is bordered by four other regions: on the northwest by the Mid-Continent Area Reliability Coordination Agreement (MARCA), on the southwest by the Southwest Power Pool (SWPP), on the southeast by the Southeastern Reliability Council (SERC), and on the east by the East Central Area Reliability Coordination Agreement (ECAR).

There exists interregional coordination between electric power systems within the MAIN region, as well as between systems of the four contiguous Reliability Councils. MAIN has agreements and interconnections to trade power and energy with all of these adjacent NERC regions.

Regional Electric Power Demand

Socio-Economic Conditions

Table IV-3 summarizes the significant 1970 demographic and economic data for the MAIN region and component subregions. These data are for the study region as approximated by the Bureau of Economic Analysis (BEA) economic areas discussed in Chapter I. The map of the region is shown in Exhibit I-2, and a list of BEA areas comprising the region and subregions is given in Exhibit I-3.

The population of the entire MAIN region has been growing steadily between 1950 and 1970, at the average annual rate of 1.3 percent, slightly less than the national growth rate. The MAIN region contained approximately 18.7 million people during 1970, representing about 9 percent of the national population. The Commonwealth Edison subregion had the largest population of the three subregions in MAIN, 9.4 million in 1970, over 50 percent of the MAIN region total. The Illinois-Missouri and Wisconsin-Upper Michigan System subregions each contained 29 and 20 percent respectively of the total region population.

Total earnings originating in the MAIN region have been increasing at the average annual rate of 3.4 percent between 1950 and 1970. However, this growth rate has not kept up with the national averages. Historically, the MAIN region earnings have been representing decreasing shares of the national market. The major portions of MAIN earnings originated in the Commonwealth Edison subregion. The Illinois-Missouri and Wisconsin-Upper Michigan System subregions respectively represented 21 and 15 percent of the MAIN region earnings.

The manufacturing, trade and service sectors contributed the largest dollar volume to the 1970 total earnings in the MAIN region. The manufacturing industries produced 12 percent of the 1970 national manufacturing earnings. The construction, transportation utilities, and trade sectors each produced about 10 percent of the 1970 national earnings in their respective sectors. The individual sector earnings of the

Table IV-3

MAIN

ECONOMIC INDICATORS
1970

Sector Earnings[1/] (Million$)	MAIN	Commonwealth Edison	Wisconsin Upper Michigan System	Illinois-Missouri
Agriculture	1,473	393	382	699
Mining	318	72	57	189
Construction	3,596	2,053	617	927
Manufacturing	19,234	11,115	3,802	4,318
Transportation Utilities	4,057	2,367	591	1,099
Trade	9,627	5,655	1,599	2,373
Finance	2,752	1,696	426	630
Services	7,847	4,658	1,292	1,897
Government	7,623	3,748	1,467	2,416
Total Earnings (Million$)[1/]	56,528	31,747	10,232	14,548
Population (Thousands)	18,660	9,380	3,811	5,469
Per Capita Income ($)[1/]	3,762	4,127	3,387	3,398
Per Capita Income Relative to the U.S.	1.082	1.187	0.974	0.987

Notes: (1) Commonwealth Edison consists of BEA areas: 77,79,82.
Wisconsin-Upper Michigan System consists of BEA areas: 83,84,85,86.
Illinois-missouri consists of BEA areas: 57,58,78,112,113,114.

(2) Because of rounding, the sum of parts may not exactly equal totals.

(3) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, propriortor's income and other labor income) property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Reference [IV-3]

MAIN region industries have been representing shrinking shares of the national sector totals during the period between 1950 and 1970.

The 1970 Commonwealth Edison subregion sectoral earnings exceeds corresponding sectoral earnings in the other subregions, except in agriculture and mining. The 1970 agriculture and mining earnings originating in the Illinois-Missouri subregion exceed the earnings of the other two subregions. All three of the subregions are dependent upon manufacturing, trade and service industries for a major portion of the total earnings. The government sector also provides a significant amount of income in each of the subregions.

The total personal income within the MAIN region is growing steadily at about the same rate as the total earnings. However, personal income growth has not been as high as the national average. The MAIN region per capita income has been increasing at the average annual rate of 2.3 percent since 1950. Historically, the per capita income has been higher than the national average. However, the disparity between national and regional averages has been decreasing. The 1970 per capita income was about 8 percent higher in the MAIN region than in the United States. The 1970 per capita income in the Commonwealth Edison subregion was 19 percent higher than the national average, and 10 percent higher than the MAIN regional averages. The Illinois-Missouri and Wiconsin-Upper Michigan System subregions both have average per capita income lower than the national average. The high per capita income of MAIN is a result of the high per capita income within the Commonwealth Edison subregion.

Peak Demand

MAIN has a summer peak of 33.4 GW as shown on Table IV-4. The Commonwealth Edison, Illinois-Missouri and Wisconsin-Upper Michigan System subregions have summer peaks of 13.9, 13.0, and 6.5 GW, respectively. The annual historic peaks for MAIN and the three subregions are shown in Exhibit IV-3 for the years 1971-1977. The annual growth rates and the average annual growth rate over a five year period for the system demand of these subregions is also shown in Exhibit IV-3. The peak demand for MAIN increased from 24.9 GW in 1971 to 33.4 GW in 1977, an average annual growth rate of 4.5%. This is reflective of the trends in the three study subregions as well.

Energy Demand

The energy output for MAIN in 1977 was 161.1 GW. Energy output for MAIN in 1977 exceeded the 1976 value by 5.2%. The energy increase from 1975 to 1976 was 4.3%. Energy output for the Commonwealth Edison, Illinois-Missouri and Wisconsin-Upper Michigan System in 1977 was 65.1, 61.4 and 34.6 GWh, respectively.

Table IV-4

MAIN

ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR
1977

	Annual Energy GWh	Peak1/ Demand MW	Month of Peak Demand	Annual Load Factor, %
MAIN	161,081	33,404	July	55.0
Commonwealth Edison	65,103	13,932	July	53.3
Wisconsin-Upper Michigan System	34,600	6,498	July	60.8
Illinois-Missouri	61,378	12,973	July	54.0

1/ Coincident Peak
Reference [IV-1]

Consumer Categories. Energy consumption as percent of total for the consumer categories (residential, commercial, and industrial) for utilities in each of the three subregions is given in Table IV-5. Annual growth rates of electric demand by the consumer categories for the period 1973-1977 are given in Exhibit IV-4. In general, annual growth rates for total energy consumption in 1974 for the three subregions had a negligible increase or a decrease from the previous year because of the 1973 oil embargo. The industrial sector in Commonwealth Edison and the Wisconsin Upper Michigan System subregions experienced a substantial decrease in energy growth in 1974 and 1975, while in 1974 and 1976 decreases in residential growth rates were experienced in Commonwealth Edison and the Illinois-Missouri subregions.

Table IV-5

MAIN

Energy Consumption By Consumer Categories
(Percent of Total)
1977

	Residential	Commercial	Industrial	Total
Representative Utilities				
COMMONWEALTH EDISON	31.6	68.4 1/		100.0
ILLINOIS-MISSOURI				
Central Illinois Public Service Company	33.9	66.1 1/		100.0
Illinois Power Company	30.6	69.4 1/		
Union Electric Company	34.6	29.6	35.8	100.0
WISCONSIN-UPPER MICHIGAN SYSTEM				
Madison Gas and Electric	37.2	54.8	8.0	100.0
Upper Peninsula Power Company	41.0	22.7	36.3	100.0
Wisconsin Electric Power Company 2/	34.3	27.3	38.4	100.0
Wisconsin Power and Light Company	40.0	42.0	18.0	100.0
Wisconsin Public Service Corporation	5.0	95.0 1/		100.0

1/ Commercial and Industrial are combined.
2/ Includes Wisconsin Michigan Power Company.

Source: The 1977 Annual Reports for the respective utilities.

Load Characteristics

The monthly energy and peak demands for 1977 are shown on Table IV-6. The peak demands for all three sub-regions occurred in July. The system loads are also represented in terms of seasonal variations, as shown in Exhibit IV-5. The first full weeks in April, August, and December in 1977 were chosen to represent the variations in demand on the systems during the year. The peaks for the three weeks are shown relative to the annual peak for each utility. The exhibit also shows the weekly load factors. From the data it appears that August was the month with the highest peak loads followed closely by December. In the Wisconsin-Upper Michigan System the December peaks appear to be slightly higher than those in August. Weekly load duration curves for representative utilities in MAIN are given in Exhibit IV-6.

Regional Electric Power Supply

Existing Generating Facilities

MAIN had a 1977 winter generating capability of 41.3 GW which is provided by the sources as shown in Exhibit IV-7. All of the electric utilities which report to MAIN, members, associate members and non-members, are represented. Generating capability by types of plants in 1977 for MAIN and the three subregions is shown in Table IV-7. Coal-fired steam is the bulk source of generation, supplying about 67% of MAIN's total capability. It represents the highest percent of total subregion capability in Illinois-Missouri at 86.0 with the Wisconsin-Upper Michigan and Commonwealth Edison subregions having 62.5 and 49.4%, respectively. Nuclear plants provide a substantial portion of the capability in the Commonwealth Edison and Wisconsin-Upper Michigan sub-regions, with 29.9 and 19.8%, respectively. Peaking plants make up about 10% of the total capability in MAIN. Combustion turbines (oil) are the main sources of peaking power in the Commonwealth Edison and Wisconsin-Upper Michigan System sub-regions. Hydropower contributes an additional 3.2% in the Wisconsin-Upper Michigan System. The Illinois-Missouri sub-region has about 4% hydro capability with an additional 3.4% of combustion turbine to supply peaking power.

Current Role of Hydropower

Hydropower, including conventional hydroelectric and pumped storage plants, represents about 1.4 percent of the

Table IV-6

MAIN

MONTHLY ENERGY AND PEAK DEMANDS
1977

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	1977
MAIN													
Peak Demand, MW	25,918	23,904	22,595	22,534	27,531	28,913	33,404	29,468	27,449	22,020	24,949	26,439	34,404
Net Energy, GWh	14,911	12,365	12,788	11,697	13,209	13,420	15,965	14,346	12,711	12,411	12,883	14,375	161,081
Load Factor, %	77.3	77.0	76.1	72.1	64.5	64.5	64.2	65.4	64.3	75.8	71.7	73.1	55.0
COMMONWEALTH EDISON													
Peak Demand, MW	10,323	9,497	9,138	9,217	11,974	12,236	13,932	12,013	10,733	8,994	9,832	10,551	13,932
Net Energy, GWh	5,948	5,033	5,232	4,778	5,432	5,379	6,397	5,736	5,078	5,075	5,234	5,781	65,103
Load Factor, %	77.4	78.9	77.0	72.0	61.0	61.1	61.7	64.2	65.7	75.8	73.9	73.6	53.3
ILLINOIS-MISSOURI													
Peak Demand, MW	9,906	9,046	8,224	8,148	9,968	10,830	12,973	11,724	11,541	8,026	9,524	10,045	12,973
Net Energy, GWh	5,742	4,595	4,671	4,283	4,919	5,213	6,425	5,705	4,955	4,601	4,835	5,434	61,378
Load Factor, %	77.9	75.6	76.3	73.0	66.3	66.9	66.6	65.4	59.6	77.1	70.5	72.7	54.0
WISCONSIN UPPER MICHIGAN SYSTEM													
Peak Demand, MW	5,689	5,361	5,235	5,170	5,590	5,847	6,498	5,732	5,176	5,001	5,594	5,843	6,498
Net Energy, GWh	3,221	2,737	2,886	2,636	2,858	2,828	3,143	2,905	2,678	2,734	2,815	3,159	34,600
Load Factor, %	76.1	76.0	74.1	69.9	68.7	67.2	65.0	68.1	71.9	73.5	69.9	72.7	60.8

Reference [IV-1]

Table IV-7

MAIN

GENERATING CAPABILITY
(Percent of Total)
1977

Capability, MW	Commonwealth Edison	Illinois-Missouri	Wisconsin Upper Michigan System	Main Total
Summer	16,329	16,586	7,463	40,378
Winter	16,909	16,758	7,618	41,285
Generation Mix in Winter, %				
Nuclear	29.9	-	19.8	15.9
Steam Turbine				
Gas	-	0.3	0.1	0.2
Coal	49.4	86.0	62.5	66.6
Oil	9.6	6.2	4.5	7.2
Hydroelectric	-	2.0	3.2	1.4
Pumped Storage	-	1.8	-	0.7
Combustion Turbine				
Gas	-	0.6	-	0.3
Oil	7.4	2.8	5.6	5.3
Internal Combustion				
Oil	0.1	0.3	0.6	0.3
Others	3.6	-	3.4	2.1
Total	100.0	100.0	100.0	100.0

Reference [IV-1]

MAIN region generating capability, as compared to about 14 percent of the 1977 national capability. As shown in Table IV-8, the total hydro capability is controlled by 6 investor-owned utilities (862 MW) and 2 municipalities (13 MW). There are hydro facilities in all of the sub-regions. The two largest conventional hydroelectric stations in the region are Keokula (119 MW) on the Mississippi River between Illinois and Iowa, and Osage River in Missouri. In Wisconsin, Chippewa, and St. Croix are developed extensively for hydropower by a series of relatively small plants which recover the useful energy available. The same is true of the Menominee River in Upper Michigan. There are other small hydropower plants scattered throughout Wisconsin and Upper Michigan. It is an item of interest that the first hydroelectric station in electric public utility service in the United States was in the MAIN region and many of the plants now operating in the region are among the oldest operating in the United States. However, in the Commonwealth Edison subregion, hydropower installation is very small because of the lack of sites having large natural fall.

Hydroelectric plants are owned partly by industrial companies who utilize the output directly in their processes. Others are part of utility systems and are operated to produce capacity and energy for thermal replacement as streamflow is available. A few plants benefit from long term storage, which is regulated to make capacity and energy available to suit load requirements.

Currently there is one pumped storage plant in operation, the 300 MW Taum Sauk plant in Missouri. Commonwealth Edison is purchasing a portion of Ludington pumped storage, which is in the ECAR region, on a declining share basis until the ECAR region will be able to utilize the full output. Taum Sauk is operated primarily as reserve; the Commonwealth Edison portion of Ludington is used actively to improve thermal economy.

Load Resource Analysis

Demand-Supply Balance

The MAIN realiability council primarily is a summer peaking system. All three subregions in MAIN, Commonwealth Edison, Illinois-Missouri and the Wisconsin-Upper Michigan System experienced annual peak demands of 14.5, 10.5 and 6.5 GW in July of 1977. The 1977 non-coincident peak for MAIN was 35.0 GW and the summer generating capability was 42.1 GW, as shown in Table IV-9. All subregions have adequate reserve margins.

Table IV-8

MAIN

OWNERSHIP OF HYDRO 1/
As of January 1, 1978

	Investor-Owned	Municipal	Total
MAIN			
Number of Utilities	6	2	8
Capability, MW			
Conventional Hydro	562	13	575
Pumped Storage	300	-	300
Total, MW	862	13	875
%	98.5	1.5	100.0
COMMONWEALTH EDISON			
Number of Utilities	-	-	-
Capability, MW			
Conventional Hydro	-	-	-
Pumped Storage	-	-	-
Total, MW	-	-	-
%	-	-	-
ILLINOIS-MISSOURI			
Number of Utilities	2	-	2
Capability, MW			
Conventional Hydro	333	-	333
Pumped Storage	300	-	300
Total, MW	633	-	633
%	100.0	-	100.0
WISCONSIN-UPPER MICHIGAN SYSTEM			
Number of Utilities	4	2	6
Capability, MW			
Conventional Hydro	229	13	242
Pumped Storage	-	-	-
Total, MW	229	13	242
%	94.6	5.4	100.0

Note: The above are plants reported to DOE by Reliability Councils. In addition, small unreported plants (primarily industrial and Municipal) in MW are approximately as follows: Commonwealth Edison-5; Illinois-Missouri-13 Municipal, 11 Investor-owned: Wisconsin Upper Michigan System-2 Cooperative, 73 Industrial. Total 104.

Reference [IV-1, IV-4 and IV-4]
1/ Based on winter capability.

Table IV-9
MAIN

RESOURCES, DEMAND AND MARGIN
(Projected For 1978)

	Commonwealth Edison		Illinois-Missouri		Wisconsin Upper Michigan System		MAIN	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Resources in MW								
Net Capacity	16,347	17,303	17,541	17,737	8,170	8,529	42,058	43,569
Scheduled Imports	1,124	624	701	458	0	0	1,825	1,082
Scheduled Exports	90	90	1,351	1,453	11	10	1,452	1,553
Total Resources	17,381	17,837	16,891	16,742	8,159	8,519	42,431	43,098
Demand in MW								
Peak Hour Demand	14,450	11,400	13,826	10,937	6,727	6,505	35,003	28,842
Interruptable Demand	0	0	45	45	21	69	66	114
Demand Requirements	14,450	11,400	13,781	10,892	6,706	6,436	34,937	28,728
Margin in MW								
Margin	2,931	6,437	3,110	5,850	1,453	2,083	7,494	14,370
Scheduled Outage	197	2,745	0	1,590	10	422	207	4,757
Adjusted Margin	2,734	3,692	3,110	4,260	1,443	1,661	7,287	9,613
Margin in Percent of Demand Requirements	18.9	32.4	22.6	39.1	21.5	25.8	20.9	33.5
Margin in Percent of Operable Resources	15.7	20.7	18.4	25.4	17.7	19.5	17.2	22.3

Reference [IV-1]

Exports and Imports

MAIN, as previously mentioned, has agreements and interconnecting facilities to trade energy with the four reliability councils which border it. Currently, MAIN is an annual net exporter, with transfer capabilities as shown in Table IV-10. Although MAIN is a net exporter of power annually, it is a net importer for the summer. Commonwealth Edison is the only subregion of the three that is a net importer for that season (see Table IV-9). The relative magnitude of the imports for Commonwealth Edison to those of the other two subregions is responsible for MAIN's summer net import status.

Table IV-10

MAIN

EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS (MW)
1978

From		To
MAIN	4000	ECAR
ECAR	3400	MAIN
MAIN	1050	MARCA
MARCA	1100	MAIN
MAIN	3000	SERC (TVA)
SERC (TVA)	2500	MAIN
MAIN	2100	SWPP
SWPP	1300	MAIN

Reference [IV-2]

Reserve Margins and Regional System Reliability

Commonwealth Edison's reserve margin criteria is 14% of the summer peak demand period and 24% of the winter. The Illinois-Missouri subregion uses annual criteria to establish reserve requirements for each of its members. This guideline states that reserves should be equal to or greater than 15% of the highest forecasted monthly demand and 50% of the capability of the largest generating unit. The Wisconsin-Upper Michigan System subregion specifies a minimum reserve capacity of 15% of the adjusted demand. Table IV-9 shows the utility to be well within its reserve requirement. These reserve criteria are determined to produce a more reliable system.

References

IV-1 MAIN, "1978 Reply to Appendix A-2 of FPC Order No. 383-4, Docket R-362," April 1, 1978.

IV-2 NERC, "8th Annual Review of Overall Reliability of the North American Bulk Power Systems", August 1978.

IV-3 U.S. Water Resources Council, "1972, OBERS Projections," Volume 1-2, Washington, D.C., April, 1974.

IV-4 FPC, "Hydroelectric Power Resources of the United States, Developed and Undeveloped, "Washington D.C., January 1, 1976.

IV-5 Department of Energy, "Inventory of Power Plants in the United States," Washington D.C., December 1977.

Chapter V

MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT MARCA

Introduction

This chapter describes the Mid-Continent Area Reliability Coordination Agreement (MARCA). The regional power systems, electric power demand and supply, and the load resource balance are presented.

Regional Power System

Delineation of the Region

Exhibit I-1 shows the boundaries of the MARCA Region. It covers the upper-midwestern part of the United States, and the province of Manitoba in Canada. In this study, the Canadian utilities are not included. MARCA area includes all or part of the following seven states - [V-1][1/]

North Dakota	all
Minnesota	all
Wisconsin	western part
Iowa	all
Nebraska	major part
South Dakota	major part
Montana	eastern part

MARCA members serve 3.6 million customers and a population of 10 million. Prior to the formation of NERC, the area presently represented by MARCA included three formal power pools which coordinated the planning and/or operation of their bulk power facilities with contractural agreements that established each member's responsibilities. The formal pools in this area included the Upper Mississippi Valley Power Pool with 13 members, the Iowa Power Pool with six members, and the Missouri Basin Systems Group with four major members. An informal power pool, the Mid-Continent Area Power Planners (MAPP), was formed primarily to develop broad plans for expansion of generation and high capacity interconnections, to reduce the cost and improve the reliability of electric service. In 1970, the membership in MAPP totaled 109 systems, and today includes most of the members of the three formal power pools described above.

1/ Numbers in brackets refer to references listed at the end of this chapter.

Following the formation of NERC, the larger utilities in MAPP organized MARCA. MARCA presently has a membership of 22 large systems shown in Exhibit V-2. Otter Tail Power Company, Muscatine Power and Water, and Lincoln Electric System operate in the MARCA region and collaborate in the reporting of data with MARCA members. Manitoba Hydro-Electric Board is an associate member of MARCA, but is not represented in the data summaries since it is wholly a Canadian utility.

All 22 MARCA utilities, along with 12 smaller utilities, are members of MAPP. Data reported from the MARCA region are supplied primarily by the MAPP organization and the Otter Tail Power Company. MAPP represents over 95 percent of the net generating capability of the larger utilities in MARCA and data reported by MAPP is not further grouped by formal power pool or organization. For these reasons, MARCA is not subdivided in this chapter and all data summaries represent the region as a whole.

Ownership

MARCA has a membership of eleven investor-owned utilities, eight generation and transmission cooperatives, two public power districts, and one federal agency, Western Area Power Administration (WAPA). WAPA coordinates the marketing of power generated at hydro-plants of the Corps of Engineers, and the Bureau of Reclamation.

Three other non-member utilities are reporting. These are Lincoln Electric System, Muscatine Power and Water, both municipal systems; and Otter Tail Power Company, an investor-owned utility. Table V-1 gives a breakdown of generating capability by type of ownership for all the reporting utilities: the 22 members, and the 3 non-members.

Table V-1

MARCA

OWNERSHIP OF GENERATION SOURCES
As of January 1, 1978

Item	Investor Owned	Cooper-ative	State	Munic-ipal	Federal	Total
Number	12	8	2	2	1	25 1/
Capability 2/						
MW	13601	1990	2960	230	2455	21236
%	64.0	9.4	13.9	1.1	11.6	100.0

1/ Includes non-members: Lincoln Electric System, Muscatine Power and Water and Otter Tail Power Company

2/ Based on summer net generating capability.

Reference: [V-2]

Transmission System

As shown in Table V-2, MARCA has more than 13,000 circuit miles of transmission line at 230 KV and higher.

Table V-2

MARCA
TRANSMISSION LINES
As of January 1, 1978

Voltage (kv)	Circuit Miles
Alternating Current	
230	8,848
345	2,830
500	-
765	-
Direct Current	
250	465
400-450	1,195

Reference: [V-3]

Power Exchange and Interties between Regions

MARCA is bordered by the following NERC areas: Western Systems Coordinating Council, Southwest Power Pool, and Mid-America Interpool Network. Interregional coordination takes place between MARCA and other Reliability Councils, as well intra regional coordination between constituent systems within MARCA. Transmission and power exchange agreements between contiguous regions permit increased operational flexibility and increase dependable electric supply during emergency, short term, diversity, or economy conditions. Economy and reliability of operation are also enhanced by successful intra-regional exchange and intertie facilities.

Regional Electric Power Demand

Socio-Economic Conditions

Table V-3 summarizes 1970 earnings, population, and per capita income statistics for the study area approximating the MARCA region. The demographic and economic data were obtained by aggregating the data available for BEA areas as discussed in Chapter I. The map of MARCA and a list of BEA areas are shown on Exhibit I-2 and I-3 respectively.

The population of MARCA was increasing between 1950 and 1970. The population growth has been low, at an average annual rate of only 0.6 percent. In 1970, the MARCA population was 4.8 percent of the national population.

The MARCA earnings increased at an average annual rate of 2.9 percent between 1950 and 1970. Despite the average annual increase, the MARCA share of national earnings has been decreasing. In 1970, the MARCA area total earnings of 24.7 billion dollars represented about 4.4 percent of the nation's earnings. The 1970 MARCA economy was strongly dependent upon earnings from the manufacturing and trade sectors. Services and government were also important sectors. In 1950, agriculture had the largest sector earnings value. Although agriculture earnings have decreased, the 1970 agriculture earnings originating in the region represented 16 percent of the national total.

Per capita income has been increasing at an average annual rate of 2.6 percent between 1950 and 1970. The disparity between MARCA and U.S. per capita income has been large. Historically, the MARCA per capita income was 7.3 percent

Table V-3

MARCA
ECONOMIC INDICATORS
1970

Sector Earnings (Million $) 1/	
Agriculture	3,250
Mining	234
Construction	1,516
Manufacturing	5,049
Transportation Utilities	1,712
Trade	4,408
Finance	1,117
Services	3,352
Government	3,987
Total Earnings (Million $) 1/	24,669
Total Population (Thousand)	9,853
Per Capita Income ($) 1/	3,214
Per Capita Income Relative to U.S.	0.925

Notes: (1) The MARCA Region is approximated by BEA areas: 80,81,87,88,89,90,91,92,93,96,97,98,99,100,101,102, 103,104,105,106,107,108.

(2) The sum of earnings does not equal the total since some data for individual BEA sector earnings was deleted to avoid disclosure of data pertaining to a particular establishment.

(3) Per capita income is total income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Reference [VI-5]

lower than the national average in 1950, and 9.4 percent lower in 1962. During 1970, the MARCA per capita income of $3,214 was about 7.5 percent lower than the national average.

Peak Demand

Exhibit V-3 gives the historical annual energy, peak demand, and load factor for MARCA. The highest peak demand observed during 1977 was 17,549 MW, in July.

Table V-4 gives the annual energy, peak demand, and load factor for some representative electric utilities of MARCA, whose peak demand are 52% of the total.

Table V-4

MARCA
ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Representatives Utilities	Annual Energy GWH	Peak Demand MW	Month of Peak Demand	Annual Load Factor %
Northern States Power Co.	20,186	4,278	July	53.9
Nebraska Public Power District	5,448	1,480	July	64.7
Iowa Power & Light Co.	4,392	1,064	July	47.1
Iowa Electric Light & Power Co.	5,118	1,019	July	57.3
Minnesota Power & Light Co.	5,626	973	June	66.0
Dairyland Power Cooperative	2,508	576	December	49.7

Reference: [V-4]

Energy Demand

In 1977, the total net energy in MARCA was 85,738 GWH. Annual growth rates of electric energy consumption by consumer categories are shown in Exhibit V-4. These categories are residential, commercial, and industrial. The growth rates of the total energy consumption by these three categories are also given.

Table V-5 presents the 1977 energy consumption by consumer categories for representative utilities in MARCA.

Table V-5

MARCA
ENERGY CONSUMPTION BY CONSUMER CATEGORIES
1977 - (Percent of Total)

Company	Rural and Residential	Commerical	Industrial	Others	Total
Interstate Power Co.	30.3	20.5	39.7	9.5	100.0
Iowa Electric Light & Power Co./Central Iowa Power Cooperative[1/]	37.6	25.1	29.4	7.9	100.0
Iowa Power & Light Co.	38.2	23.9	35.3	2.6	100.0
Lake Superior District Power Co.	30.6	19.3	38.7	11.4	100.0
Minnesota Power & Light Co.	10.9	8.6	55.1	25.4	100.0
Northern States Power Co.	24.3	11.5	33.7	30.5	100.0
Omaha Public Power District	32.9	30.3	25.0	11.8	100.0
Otter Tail Power Co.	35.9	45.4[2/]		18.7	100.0

1/ Percentages listed are for 1976.
2/ Percent shown is for both commerical and industrial use.

SOURCE: 1977 Annual Reports of the above listed utilities.

Load Characteristics

The annual load factor in MARCA for 1977 was 55.8%. Exhibit V-3 gives the historical load factor for the period 1970-1977. Exhibit V-5 gives weekly load factors during the first week of April, August, and December for representative utilities. The magnitude of the weekly peak load demand and its date of occurrence are also provided. Most of the systems experience their peak demand in summer. The annual load factors range from 47.1 to 66.0 percent during 1977. Weekly load duration curves for representative utilities are shown in Exhibit V-6.

Table V-6 gives the monthly energy, peak demand and load factor of MARCA during the twelve months of 1977.

Regional Electric Power Supply

Existing Generating Facilities

Exhibit V-7 gives the winter generating capability by type of plant for the MARCA systems. Winter capability is estimated to be 21,847 MW, and the summer capability 21,236 MW. Table V-7 summarizes the winter generating capability by type of plants for MARCA.

Coal-fired steam turbines furnish the bulk of the electric resources which exist in MARCA. Nuclear, combusion turbine, hydropower, and other types of power facilities are also coordinated within the system.

Table V-6

MARCA
MONTHLY ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Month	Peak Hour Demand-MW	Net Energy GWH	Load Factor, %
January	14,903	8,525	76.9
February	13,707	7,051	76.5
March	12,603	6,730	71.8
April	12,234	6,292	71.4
May	13,457	6,663	66.6
June	15,801	7,041	61.9
July	17,549	8,337	63.8
August	14,078	7,086	67.6
September	13,038	6,406	68.2
October	12,120	6,555	72.7
November	13,552	6,910	70.8
December	15,097	8,142	72.5
1977	17,549	85,738	55.8

Reference: [V-2]

Table V-7

MARCA
GENERATING CAPABILITY BY TYPE OF PLANTS 1/
1977

	MW	%
Nuclear	3,750	17.2
Steam Turbine		
Gas	198	0.9
Coal	11,126	50.9
Oil	558	2.6
Combined Cycle	206	0.9
Hydroelectric	2,781	12.7
Combustion Turbine		
Gas	59	0.3
Oil	2,843	13.0
Internal Combustion		
Oil	326	1.5
TOTAL	21,847	100.0

Reference: [V-2]

1/ Based on winter capability.

Current Role of Hydropower

Conventional hydropower supplies 12.7 percent of MARCA's total 1977 winter generating capability; there are no pumped storage plant facilities in MARCA. As of January 1, 1978 there were 59 hydropower plants operating within the system. Table V-8 gives the hydropower capability by utility, and Table V-9 gives a breakdown of generating capability by types of ownership. Plant capabilities range from less than 1 MW to more than 650 MW. The majority of MARCA hydropower facilities provide less than 30 MW.

The large hydropower installations in MARCA are Federal plants on the Missouri River. All Federal plants but one (Big Bend) are operated essentially as base energy plants, supplying needs of preference customers up to their ability to take the energy within their load curves, with the remaining energy being utilized by others in the area. Big Bend is operated for peaking and is marketed in the same manner as the other Federal plants. Other hydropower plants in the area are relatively small and essentially are run-of-river providing thermal replacement capacity and energy as river flow makes them available.

Table V-8

MARCA
HYDROPOWER CAPABILITY 1/
As of January 1, 1978

Utilities	Capability, 2/, MW
Dairyland Power Cooperative	16
Iowa Illinois Gas & Electric Co.	2
Lake Superior District Power Co.	13
Minnesota Power & Light Co.	106
Nebraska Public Power District	127
Northern States Power Co.	207
Otter Tail Power Co.	4
Western Area Power Administration/Upper Missouri Area	2,306
Total MARCA	2,781

1/ As reported to MARCA.
2/ Based on winter net generating capability.
Reference: [V-2]

Table V-9

MARCA
OWNERSHIP OF HYDROPOWER[1/]
As of January 1, 1978

	Investor-Owned	Cooperative	State	Federal	Total
Number of Plants	39	1	10	9	59
Summer Capability					
MW	330	21	124	2,455	2,930
%	11.3	0.7	4.2	83.8	100.0
Winter Capability					
MW	332	16	127	2,306	2,781
%	11.9	0.6	4.6	82.9	100.0

Reference: [V-2]

1/ The above plants are reported to MARCA by the utilities. In addition, small unreported plants are approximately as follows: 49 MW Industrial, 11 MW Investor-owned, and 113 MW Public (non-federal); Total 173 MW.

Load Resource Analysis

Table V-10 gives a load resource balance as projected by MARCA for the year 1978.

Table V-10

MARCA
RESOURCES, DEMAND & MARGIN
Projected for 1978

	Summer MW	Winter MW
Resources		
Net Dependable Capacity	22,268	24,152
All Scheduled Imports	880	543
All Scheduled Exports	303	362
Total Resources	22,845	22,333
Inoperable Capability	0	0
Operable Resources	22,845	24,333
Demand		
Peak Hour Demand	18,651	16,879
Interruptible Demand	193	202
Demand Requirements	18,458	16,677
Margin		
Margin	4,387	7,656
Scheduled Outage	629	1,173
Adjusted Margin	3,758	6,483
Percentage of Demand Requirements	20.4%	38.9%
Percentage of Operable Resources	16.5%	26.6%

Reference: [V-2]

Electric resources, in summer, exceed demand requirements by 3,758 MW or 16.5 percent. The adjusted margin represents 20.4 percent of the demand requirements. In winter, the resources exceed the demands by 6,483 MW or 26.6 percent. The adjusted margin represents 38.9 percent of the demand requirements. As load continues to grow in the MARCA region, reserve margins will probably decrease in winter. For 1978, MARCA is expected to be a net importer of 577 MW in summer, and 181 MW in winter. In addition, MARCA has interchange of emergency, short term, diversity and economy power with adjoining systems. Current emergency transfer capabilities between MARCA and surrounding reliability councils are shown in the following Table.

Table V-11

MARCA
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS
Projected for 1978 - MW

From		To
MARCA	1100	MAIN
MAIN	1050	MARCA
MARCA	1150	SWPP
SWPP	1000	MARCA
MARCA	100	WSCC
WSCC	100	MARCA

Reference: [V-3]

References

V-1 National Electric Reliability Council, 1977, National Report.

V-2 MARCA, "Information Report on Coordinated Regional Bulk Power Supply Programs," 1978.

V-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems," August, 1978.

V-4 Federal Power Commission, "FPC Form 12" Washington, D.C., 1977.

V-5 U.S. Water Resources Council, "1972 OBERS projections" Volume 1-2, Washington, D.C., April, 1974.

Chapter VI

NORTHEAST POWER COORDINATING COUNCIL
NPCC

Introduction

This chapter describes the Northeast Power Coordinating Council (NPCC). The regional power systems, electric power demand and supply, and load resource balance are presented.

Regional Power System

Delineation of the Region

The NPCC Region (Exhibit I-1) covers the northeastern part of the United States, and the Canadian provinces of New Brunswick, and Ontario. In this study, only the United States part of the NPCC Region is considered. NPCC is divided into two subregions, the New England subregion and the New York subregion. These two subregions include all of the states listed below:

New England:

- Maine
- New Hampshire
- Vermont
- Massachusetts
- Connecticut
- Rhode Island

New York:

- New York

NPCC commenced operation on January 19, 1966, and now supplies approximately 98% of the electric generation in the New England and New York subregions [VI-1][1/]. NPCC members located in the New England subregion are members of the New England Power Pool (NEPOOL), and systems in the New York subregion are members of the New York Power Pool (NYPP).

1/ Numbers in bracket refer to references listed at the of this chapter.

Ownership

Data presented in this study are those for all reporting utilities to NPCC. A list of reporting utilities is shown in Exhibit VI-2. It includes both members and non-members of NPCC.

Table VI-I summarizes the winter generating capabilities by ownership categories in NPCC and each subregion. The total 1977 generating capability in NPCC was 52,009 MW in the winter and 50,173 MW in the summer.

Table VI-1

NPCC

OWNERSHIP OF GENERATION SOURCES 1/
As of January 1, 1978

	Investor-Owned	Municipal	State	Total
New England				
No. of Reporting Utilities	24	12	-	36
Capability MW	20,632	656	-	21,288
%	96.9	3.1		100.0
New York				
No. of Reporting Utilities	7	3	1	11
Capability MW	23,939	134	6,648	30,721
%	77.9	0.4	21.7	100.0
NPCC				
No. of Reporting Utilities	31	15	1	47
Capability, MW	44,571	790	6,648	52,009
%	85.7	1.5	12.8	100.0

1/ Based on winter capability.

Reference: [VI-3]

Transmission System

Table VI-2 indicates the existing mileage of the bulk transmission lines for the total NPCC Area (USA and Canada).

Table VI-2

NPCC
TRANSMISSION LINES
As of January 1, 1978

Voltage (kV)	Circuit Miles
230	9,725
345	3,782
500	650

Reference: [VI-3]

Power Exchanges and Interties between Regions

For New England, annual generation and bulk transmission maintenance schedules are developed for all of the member systems, and administered by the New England Power Exchange (NEPEX), the joint dispatch agency of NEPOOL, located at West Springfield, Massachusetts. The annual generation and transmission maintenance schedules are updated monthly, and sent to New York Power Pool (NYPP), Ontario Hydro, New Brunswick Electric Power Commission, and the Michigan Electric Power Pool Control Center for their information and for coordination purposes. The same organizations keep NEPEX informed of their schedules.

The New York Power Pool (NYPP) Generator Maintenance Schedule is prepared for all of the member systems by the Power Control Center for the current and immediately succeeding year. This schedule is modified and reissued at least four times a year, and is distributed to all neighboring pools. The control center is located near Schenectady, New York.

During 1977, the region experienced several significant system disturbances. In most cases, the distrubances were caused by faults on lines, violent thunderstorms, ice, snow, and/or high winds. The distrubances resulted in loss of generation and interconnections with other regions. Delays in the construction of new transmission lines have also contributed to the region's problems. A proposed 765-kV line from the Canadian border to the vicinity of Utica, New York, and a 115-kV line in New England's Southwest Connecticut Area will help to solve these distrubances.

A close interconnection between systems in each subregion of NPCC exists. The New England subregion and the New York subregion are interconnected by a number of tie lines. Table VI-3 shows the normal and emergency transfer capabilities within NPCC and with Canada.

Table VI-3

NPCC
TRANSFER CAPABILITIES
Summer, 1978 - MW

	Normal	Emergency
New York to New England	1375	1500
New England to New York	1200	1200
New York to Ontario Hydro	550	910
Ontario Hydro to New York	730	960
New England to New Brunswick	350	350
New Brunswick to New England	600	600

Reference: [VI-2]

During 1977, NPCC participated in the following NERC reviews: [VI-2]:

- 7th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems (July 1977).

- Fossil and Nuclear Fuel for Electric Utility Generation: Requirements and Constraints - 1977-1986 (August 1977).

- A study of Interregional Energy Transfers for Conservation of Coal. Winter 1977/1978 (November 1977).

NPCC is also an active participant in the Multiregional Modeling Group (MMG), sponsored by NERC. Under the direction of the Joint Interarea Review Committee, the MAAC-ECAR-NPCC (MEN) group studies interregional transmission capabilities, and the reliability performance of the three region's interconnected systems as planned for selected future years.

Regional Electric Power Demand

Socio-Economic Conditions

Table VI-4 summarizes the significant demographic and economic data for NPCC and its two component subregions These demographic and economic data are that for the study region as approximated by the economic areas discussed in Chapter I. The map of the NPCC region is shown in Exhibit I-2, and the list of BEA areas comprising NPCC is given in Exhibit I-3.

The 1970 population of NPCC was about 29.2 million, representing 14.3 percent of the national total. The 1970 population of the New York subregion was about 65 percent of the NPCC total, with the remainder of the population in the New England subregion. The population of both the New York and New England subregions have been growing at the same average annual rate of about 1.2 percent between the years 1950 and 1970.

Total earnings originating in NPCC have accounted for about 15.9 percent of the national total. During the period 1950 through 1970, NPCC total earnings have grown at the average annual rate of 3.5 percent. The New York subregion has contributed a larger share than the New England sub-region to NPCC total earnings. Of the 89 billion dollars earned during 1970 in NPCC, 65 percent originated in the New York subregion, and 35 percent originated in the New England subregion.

The manufacturing sector was the largest single source of earnings for both NPCC subregions Trade, services and government also contributed a significant portion to the NPCC total earnings. Agriculture and mining had the lowest sector earnings value in the NPCC area. Together, the agriculture and mining sectors contributed only about 1 percent to the NPCC total earnings value. From a national standpoint, the NPCC area finance sector contributed 21 percent to the national finance sector earnings, representing a portion of national sector earnings larger than that of any other NPCC industrial sector.

Table VI-4

NPCC
ECONOMIC INDICATORS
1970

Sector Earnings 1/ (Million $)	New England	New York	NPCC
Agriculture	357	559	917
Mining	29	100	129
Construction	2,081	3,104	5,186
Manufacturing	9,764	16,894	26,658
Transportation Utilities	1,826	4,727	6,553
Trade	5,019	9,814	14,834
Finance	1,876	4,269	6,146
Services	5,331	10,276	15,607
Government	4,727	8,700	13,427
Total Earnings (Million $) 1/	31,065	58,443	89,508
Population (Thousands)	10,899	18,258	29,158
Per Capita Income ($) 1/	3,681	4,114	3,952
Per Capita Income Relative to the U.S.	1.059	1.184	1.137

Notes: (1) The New England subregion is approximated by BEA areas: 1, 2, 3, 4, 5.

(2) The New York subregion is approximated by BEA areas: 6, 7, 8, 9, 12, and a portion of 14.

(3) Sum of sector earnings may not equal total since some data for individual sector earnings was deleted to avoid disclosure of data pertaining to a particular establishment. Because of rounding, sum of parts may not equal totals.

(4) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Reference: [VI-5]

Per capita income has historically been higher in NPCC than in the Nation. During 1970, the average per capita income in the NPCC area was $3,952, about 14 percent higher than the national average. The NPCC per capita income has been growing at the average annual rate of about 2.5 percent. The New York subregion had higher per capita income than the New England subregion. The 1970 per capita income in the New York subregion was $4,114, while in the New England subregion, the per capita income was $3,681.

Peak Demand

Exhibit VI-3 gives the historical annual energy, peak demand, and load factor of NPCC and both subregions for the years 1960, 1965, and 1970 through 1977. Also included in Exhibit VI-3 are annual growth rates of annual energy, and peak demand.

For NPCC, the peak-hour demand increased by 4.7% from 1976 to 1977, compared to an annual increase of 3.0% for 1975-1976, 3.5% for 1974-1975, and a decrease of 5.4% for 1973-1974. The average of annual growth rate for the 1970-1977 period is 4.0%. For 1977, the highest peak demand was 35,448 MW in July. The winter peak was 33,767 MW (95% of the summer peak), in December.

In the New England subregion the peak demand for 1977 was 14,846 MW in December. It increased by 2.7% from 1976 to 1977, compared to an annual increase of 5.7% for 1975-1976, 7.7% for 1974-1975. The average of annual growth rate for the 1970-1977 period is 3.7%.

In the New York subregion, the peak demand for 1977 was 21,214 MW in July. It increased by 9.8% from 1976 to 1977, compared to an annual decrease of 3.5% for 1975-1976, and an increase of 2.0% for 1974-1975. The average of annual growth rate for the period 1970-1977 is 2.9%.

Table VI-5 gives the 1977 annual energy, peak demand, and load factor for the representative utilities in the New England and New York subregions.

Energy Demand

Exhibit VI-3 gives the historical annual energy of NPCC, and its subregion.

Table VI-5
NPCC

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR
NPCC - 1977

Representative Utilities	Annual Energy GWh	Peak Demand MW	Month of Peak Demand	Load Factor %
New England				
- Boston Edison Company	10,088	2,013	July	57.2
- Connecticut Light & Power Co.	10,433	1,965	December	60.6
- Harford Electric Light Co.	5,822	1,157	July	57.4
- Public Service Co. of New Hampshire	5,428	1,125	December	55.1
- United Illuminating Co.	4,899	944	July	59.2
New York				
- Niagara Mohawk Power Corporation	31,321	5,284	December	67.7
- Power Authority of the State of New York	14,130	2,386	December	67.7
- Long Island Lighting Co.	13,550	3,101	July	49.9
- New York State Electric & Gas Corporation	11,309	2,062	January	62.6
- Rochester Gas and Electric Corporation	5,370	987	July	62.0

Reference: [VI-4]

The annual demand for energy in NPCC increased by 2.0% from 1976 to 1977, (1.9% in the New England Subregion and 2.1% in the New York subregion), compared to an annual increase of 4.9% for 1975-1976, 0.0% for 1974-1975, and a decrease of 3.0% for 1973-1974. The average growth rate for the 1970-1977 period is 3.5%. In 1977, the annual energy was 194,212 GWh.

Exhibit VI-4 states the annual growth rates of energy consumption by consumer categories [residential, commercial, and industrial] for representative utilities of the New York subregion, and for the New England subregion during the years 1971 to 1977. The growth rates of the total energy consumption are stated.

Table VI-6 gives the 1977 energy consumption by consumer categories for representative utilities in the New England and New York subregions.

Load Characteristics

Exhibit VI-3 gives the load factors of NPCC, the New England subregion and New York subregion for the years 1960, 1965, and 1970 through 1977. In 1977, the load factor was 62.6% for the total NPCC, 60.3% for the New England subregion, and 61.6% for the New York subregion. Table VII-5 shows the load factors for representative electric utilities in each subregion. Exhibit VI-5 shows the weekly load factors for the first weeks of April, August, and December 1977 for representative utilities in NPCC. The magnitude of the weekly peak load demand and the date of its occurrence are also given. The weekly load curves for the first weeks of April, August, and December 1977, for representative electric utilities, are given in Exhibit VI-6.

NPCC contains both summer and winter peaking systems. There are great variations in the annual load factors, most of them ranging between 53 and 65 percent during 1977.

Table VI-7 gives the monthly energy, peak demand and load factor during the 12 months of 1977 for the New England and New York subregions, and NPCC (U.S. Only).

Table VI-6

NPCC
ENERGY CONSUMPTION BY CONSUMER CATEGORIES
1977 - (Percent of Total)

	Residential	Commercial	Industrial	Sale For Resale	Others	Total
Representative Utilities						
New England						
- Boston Edison Co.	23.4	39.4	16.4	19.7	1.1	100.0
- Northeast Utilities	36.7	27.5	24.8	10.1	0.9	100.0
- United Illuminating Company	36.2	32.8	29.5	-	1.5	100.0
New York						
- Consolidated Edison Co. of N.Y. Inc.	36.5	52.5	5.8	-	5.2	100.0
- Niagra Mohawk Power Corporation	27.9	30.5	40.6	0.1	0.9	100.0
- Long Island Lighting Company	44.2	39.1	9.0	3.1	4.6	100.0
- New York State El. & Gas Corporation	39.9	33.9	24.8	0.3	1.1	100.0
- Rochester Gas & El. Corporation	33.2	36.6	29.1	-	1.1	100.0

Sources: 1977 Annual reports of the listed utilities.

Table VI-7

NPCC
MONTHLY ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
New England												
Peak Hour Demand-MW	14,500	13,591	12,328	11,969	12,159	12,291	14,234	13,950	13,342	11,672	13,101	14,846
Net Energy GWH	7,875	6,743	6,844	6,115	6,099	6,142	6,466	6,792	6,198	6,391	6,553	7,567
Load Factor, %	73.0	73.8	74.6	70.9	67.4	69.4	61.0	65.4	64.5	73.6	69.5	68.5
New York												
Peak Hour Demand-MW	18,765	17,429	16,544	15.748	17,449	18,049	21,214	19,743	19,479	16,110	17,686	18,921
Net Energy GWH	10,512	8,978	9,515	8,826	9,193	9,101	10,125	10,283	9,216	9,170	9,203	10,305
Load Factor, %	75.3	76.6	77.3	77.8	70.8	70.0	64.1	70.0	65.7	76.5	72.3	73.2
NPCC Region (U.S. Only)												
Peak Hour Demand-MW	33,265	31,020	28,872	27,717	29,608	30,340	35,448	33,693	32,821	27,782	30,787	33,767
Net Energy GWH	18,387	15,721	16,359	14,941	15,292	15,243	16,591	17,075	15,414	15,561	15,756	17,872
Load Factor, %	74.3	75.4	76.2	74.9	69.4	69.8	62.9	68.1	65.2	75.3	71.1	71.1

Reference: [VI-2]

Regional Electric Power Supply

Existing Generating Facilities

Exhibit VI-7 shows the summer generating capability by type of plants for the New England and New York subregions.

Table VI-8 gives the total summer and winter generating capability for NPCC, New England, and New York. It also shows the total winter generating capability by type of plants. As can be seen in this table, NPCC is heavily dependent on oil to supply the energy needs of its customers.

Current Role of Hydropower

Hydropower including conventional hydroelectric and pumped storage units represents about 15.2% of the NPCC (U.S. only) 1977 generating capability as compared to about 12% for the 1977 national average. Table VI-9 gives the summer capability by utility in New England and New York subregions. Table VI-10 gives the ownership list of hydropower plants.

In the New England subregion, pumped storage capability exceeds conventional hydroelectric capability. The major pumped storage plants are: Northfield (1,000 MW) and Bear Swamp (601 MW). The total pumped storage capability represents 7.7% of the total capability. In addition, there are many small conventional hydroelectric plants representing about 6.0% of the total generating capability.

In the New York subregion, conventional hydropower represents 13.2% of the total generating capability, compared to only 3.3% for the pumped storage capability. The biggest pumped storage plant is Blenheim Gilboa with a capability of 1000 MW. The major conventional hydroelectric plants are: Moses Niagara Lewiston, and Moses Power Dam.

In addition to their intermediate or peaking role, hydroelectric powerplants provide a greater flexibility to the systems in which they operate. Regardless of the size of the hydropower projects, the energy which they generate helps to satisfy the regional power needs while offsetting the higher cost of energy production based on oil consumption which the region is highly dependent upon.

Table VI-8

NPCC
SUMMER AND WINTER GENERATING CAPABILITY
1977

	NPCC	New England	New York
Summer Capability-MW	50,173	20,619	29,544
Winter Capability-MW	52,009	21,288	30,721
Generation in Winter (Percentage)			
Nuclear	14.9	19.6	11.5
Steam Turbine			
Coal	7.6	2.4	11.2
Oil	49.4	54.7	45.6
Combined Cycle	0.6	1.5	
Hydroelectric	10.1	6.0	13.2
Pumped Storage	5.1	7.7	3.3
Combustion Turbine			
Oil	11.7	6.9	15.0
Internal Combustion			
Oil	0.6	1.2	0.2
TOTAL	100.0	100.0	100.0

Reference: [VI-2]

Table VI-9

NPCC
HYDROPOWER CAPABILITY[1/]
As of January 1, 1978

	Conventional Hydro, MW	Pumped Storage, MW
New England		
- Bangor Hydro Electric Co.	29	-
- Connecticut Light & Power Co.	98	561 (31 Rocky River/ 530 Northfield Mountain)
- Hartford Electric Light Co.	10	280 (Northfield Mountain)
- Holyoke Gas & Electric Department	2	-
- Holyoke Water Power Co.	29	-
- Main Public Service Co.	2	-
- City of Norwich	3	-
- Western Massachusetts Electric Co.	105	190 (Northfield Mountain)
- Central Maine Power Co.	302	-
- Green Mountain Power	71	-
- New England Electric System	584	601 (Bear Swamp)
- Public Service Co. of New Hampshire	48	-
Subtotal	1,283	1,632[2/]
New York		
- Central Hudson Gas & Electric Corp.	46	-
- New York State Electric & Gas Corp.	40	-
- Niagara Mohawk Power Corp.	661	-
- Orange and Rockland Utilities, Inc.	44	-
- Power Authority of the State of New York	3,200	1,000 (Blenheim Gilboa)
- Rochester Gas & Electric Corporation	50	-
Subtotal	4,401	1,000
NPCC TOTAL	5,324	2,632

1/ As reported to NPCC; based on winter capability.

2/ 1,000 MW of the total 1,632 MW is located at a site at Northfield Mountain, Massachusetts, and the various utilities have shares in it.

Reference: [VI-2]

Table VI-10

NPCC
OWNERSHIP OF HYDROPOWER[1/]
As of January 1, 1978

	Investor-Owned	Municipal	State	Total
New England				
Conventional Hydro				
- Number of Utilities	10	2	-	12
- Capability MW	1,278	5	-	1,283
%	99.6	0.4	-	100.0
Pumped Storage				
- Number of Utilities	4	-	-	4
- Capability MW	1,632	-	-	1,632
%	100.0	-	-	100.0
New York				
Conventional Hydro				
- Number of Utilities	5	-	1	6
- Capability MW	841	-	3,200	4,041
%	20.8	-	79.2	100.0
Pumped Storage				
- Number of Utilities	-	-	1	1
- Capability MW	-	-	1,000	1,000
%	-	-	100.0	100.0
NPCC				
Conventional Hydro				
- Number of Utilities	15	2	1	18
- Capability MW	2,119	5	3,200	5,324
%	39.8	0.1	60.1	100.0
Pumped Storage				
- Number of Utilities	4	-	1	5
- Capability MW	1,632	-	1,000	2,632
%	62.0	-	38.0	100.0

Note: The above are plants reported to NPCC by the utilities. In addition, small unreported plants are approximately as follows: New England: 270 MW Industrial, 85 MW Investor-owned, and 25 MW Publicly-owned (non-federal). Total of 380 MW. New York: 52 MW Industrial, 12 MW Investor-owned, and 17 MW Publicly-owned (non-federal). Total of 81 MW.

1/ Based on winter generating capability.

Load Resource Analysis

Table VI-11 gives a detailed description of the capability, demand and margin for NPCC (U.S. only) and the New England and New York subregions. In the New England subregion, the adjusted margin averages 22% of the operable resources, and represents 31.6% of the demand requirements. In the New York subregion, the adjusted margin is bigger, especially during winter: 45.3% of the demand requirements, and 29.5% of the operable resources. In summer, the adjusted margin represents 33.3% of the demand requirements, and 23.8% of the operable resources. For 1978, NPCC is expected to be a net importer of 760 MW in summer, and 452 MW in winter. In addition, NPCC has interchange of emergency, short term, diversity, and economy power with adjoining systems. Current emergency transfer capabilities between NPCC and surrounding reliability councils are shown in Table VI-12.

Table VI-11

NPCC
RESOURCES, DEMAND & MARGIN
Projected for 1978

	NPCC		New England		New York	
	Summer	Winter	Summer	Winter	Summer	Winter
RESOURCES IN MW						
Net Dependable Capability	50,687	53,118	20,563	21,789	30,124	31,329
All Scheduled Imports	910	602	601	602	309	0
All Scheduled Exports	150	150	0	0	150	150
Total Resources	51,447	53,570	21,164	22,391	30,283	31,179
Inoperable Capability	640	644	0	0	640	644
Operable Resources	50,807	52,926	21,164	22,391	29,643	30,535
DEMAND IN MW						
Peak Hour Demand	35,710	35,520	14,500	15,780	21,210	19,740
Interruptible Demand	25	0	0	0	25	0
Demand Requirements	35,685	35,520	14,500	15,780	21,185	19,840
MARGIN IN MW						
Margin	15,122	17,406	6,664	6,611	8,458	10,795
Scheduled Outage	3,309	3,600	1,909	1,800	1,400	1,800
Adjusted Margin	11,813	13,806	4,755	4,811	7,058	8,995
Percentage of Demand Requirements	33.1	38.9	32.8	30.5	33.3	45.3
Percentage of Operables Resources	23.3	26.1	22.5	21.5	23.8	29.5

Reference: [VI-2]

Table VI-12

NPCC
EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABILITY COUNCILS
Projected for 1978

From		To
NPCC	2,700	ECAR
ECAR	1,250	NPCC
NPCC	3,300	MAAC
MAAC	1,000	NPCC

Reference: [VI-3]

REFERENCES

VI-1 National Electric Reliability Council, "1977 Annual Report."

VI-2 NPCC, "Data on Coordinated Regional Bulk Power Supply Programs," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

VI-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems," August 1978.

VI-4 Federal Power Commission, "FPC Form 12," Washington D.C., 1977.

VI-5 U.S. Water Resources Council, "1972, OBERS projections," Volume 1-2, Washington, D.C., April 1974.

Chapter VII

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
SERC

Introduction

This chapter describes the Southeastern Electric Reliability Council (SERC). The regional power systems, electric power demand and supply, and load resource balance are presented.

Regional Power System

Delineation of Region

The SERC Region covers the Southeastern part of the United States. It includes all or part of the following ten states:

Virginia	-	southeastern part
West Virginia	-	small part
North Carolina	-	all
South Carolina	-	all
Georgia	-	all
Florida	-	all
Alabama	-	all
Mississippi	-	eastern and northern parts
Tennessee	-	all
Kentucky	-	southwestern part

The SERC Region encompasses a large geographical area having four relatively well defined subregions. Exhibit I-1 shows the boundaries between the subregions and the other councils. The four subregions are:

VACAR	Virginia-Carolinas
TVA	Tennessee Valley
SOUTHERN	Southern Companies
FLORIDA	Florida

Ownership

SERC was formed on January 24, 1970 and membership is open to all power utilities in the region [VII-1][1/]. Exhibit VII-2 gives the list of the reporting members of the Council, as well as other utilities in the SERC area which are not members. Table VII-1 summarizes the winter generating capability by ownership categories in SERC and each sub-region. The total 1977 generating capability in SERC was 106,901 MW in the winter and 105,254 MW in the summer.

Transmission System

A major objective of SERC is to assure that the Regional transmission system is planned so that cascading outages will not result from any foreseeable contingencies. Each individual SERC member is responsible for its local power supply area, and has internal criteria relating to the more common contingencies.

Table VII-2 indicates the existing mileage of the bulk transmission lines of the SERC Area.

It is reported by SERC that the regional transmission system performed well during 1977. A 765-kV line in Virginia was originally scheduled for operation by the summer of 1977. Extended certification proceedings before the Virginia State Corporation Commission have delayed this line until the winter of 1981. A 500-kV loop around the Washington D.C. area is under construction and is scheduled for completion in 1980. It is needed to improve the power transfer capabilities between MAAC and the neighboring regions of ECAR and SERC.

Power Exchanges and Interties between Subregions

Each sub-region conducts studies of specific situations with all of its neighboring systems as required. A permanent VACAR Planning Task Force conducts the joint studies of the bulk power facilities of all the members of VACAR, and coordinates the studies made by VACAR and its member systems with others.

1/ Numbers in brackets refer to references listed at the end of this chapter.

Table VII-1

SERC OWNERSHIP OF GENERATION SOURCES[1/]
As of January 1, 1978

		Investor-Owned	Municipal	Cooperative	State	Federal	Total
VACAR							
No. of Utilities		5	-	-	1	1	7
Capability	MW	31,956	-	-	1,416	515	33,887
	%	94.3	-	-	4.2	1.5	100.0
TVA							
No. of Utilities		2	-	-	-	2	2
Capability	MW	408	-	-	-	25,866	26,274
	%	1.6	-	-	-	98.4	100.0
SOUTHERN							
No. of Utilities		6	-	2	1	1	10
Capability	MW	22,334	-	348	26	1,419	24,127
	%	92.6	-	1.4	0.1	5.9	100.0
FLORIDA							
No. of Utilities		3	9	1	-	-	13
Capability	MW	18,103	4,496	14	-	-	22,613
	%	80.0	19.9	0.1	-	-	100.0
SERC							
No. of Utilities		16	9	3	2	4	34
Capability	MW	72,801	4,496	362	1,442	27,800	106,901
	%	68.1	4.2	0.3	1.4	26.0	100.0

1/ Based on winter capability.
Reference: [VII-2]

Tennessee Valley Authority participates in joint operating studies with members of VACAR, SOUTHERN, and the American Electric Power System (AEP, member of ECAR).

The Power Coordination Center of Southern Companies Services, Inc. has responsibility of coordination of the operation of the SOUTHERN subregion bulk power supply. In addition to normal contractual agreements for capacity and energy transactions with interconnected neighboring systems, the SOUTHERN subregion has bilateral reliability agreements with the VACAR subregion Florida Power Corporation, Middle South System, and Tennessee Valley Authority. These reliability agreements provide for coordination of planning and operation for reliable interconnected operations.

Table VII-2

SERC
TRANSMISSION LINES
As of January 1, 1978

Voltage (kV)	Circuit Miles
230	15,215
345	2
500	4,010

Reference: [VII-3]

The FLORIDA subregion has coordinated its planning and operating efforts since the late 1950's. A System Planning Committee was formed in 1970 to perform primarily load flow studies and stability analyses. This committee studies the future requirements of the FLORIDA sub-region.

Regional Electric Power Demand

Socio-Economic Conditions

Table VII-3 summarizes the significant demographic and economic data for SERC and its subregions. These demographic and economic data are that for the study regions as approximated by the BEA economic areas discussed in Chapter I. The map of the region is shown in Exhibit I-2 and the list of BEA areas comprising the regions is given in Exhibit I-3.

Population of the SERC region has been growing at the average annual rate of 1.7 percent between the years 1950 and 1970. During this historical period, the SERC region population has represented increasing portions of the national total. The 1970 SERC population of about 33 million represented 16 percent of the national population. The VACAR subregion contained 38 percent of the 1970 SERC population. The SOUTHERN and FLORIDA subregions respectively contained 26 and 20 percent of the 1970 SERC population. The FLORIDA subregion had an usually high population growth rate of 4.5 percent between 1950 and 1970. The Tennessee Valley subregion had the lowest portion of the 1970 SERC region population.

Total earnings in the SERC region have been increasing at the average annual rate of 5.2 percent. Earnings growth

Table VII-3

SERC
ECONOMIC INDICATORS
1970

	VACAR	TVA	SOUTHERN	FLORIDA	SERC
Sector Earnings 1/ (Million $)					
Agriculture	1,089	616	863	705	3,273
Mining	52	91	138	63	344
Construction	2,003	611	1,043	1,424	5,082
Manufacturing	7,336	3,490	5,103	2,257	18,186
Transportation Utilities	1,911	573	1,380	1,309	5,173
Trade	4,901	1,812	3,226	3,116	13,056
Finance	1,429	458	883	1,036	3,807
Services	4,976	1,086	2,383	2,937	11,383
Government	10,642	2,147	4,170	2,855	19,814
Total Earnings (Million $) 1/	34,341	11,524	19,189	15,703	80,756
Population (Thousands)	12,741	5,431	8,552	6,619	33,344
Per Capita Income ($) 1/	3,211	2,624	2,741	3,246	3,002
Per Capita Income Relative to the U.S.	0.924	0.755	0.789	0.934	0.864

Note: VACAR subregion is approximated by BEA Areas: 18, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31.

TVA subregion is approximated by BEA Areas: 46, 47, 48, 49, 50.

SOUTHERN subregion is approximated by BEA Areas: 32, 33, 39, 40, 41, 42, 43, 44, 45, 136, 137.

FLORIDA subregion is approximated by BEA Areas: 34, 35, 36, 37, 38.

The sum of sector earnings may not equal total earnings since some data for individual BEA sector earnings was deleted to avoid disclosure of data pertaining to a particular establishment. Due to rounding, the sum of parts may not exactly equal totals.

Reference: [VII-5]

1/ Constant 1967 dollars.

in the SERC region has been significantly higher than overall national growth. The SERC region earnings have historically been representing increasing shares of the national market. The government, followed by manufacturing, has represented the largest industrial earnings sectors in SERC. The government and agriculture sectors in SERC have been important with respect to national sectoral earnings, each representing 20 and 16.7 percent of respective national sector earnings. Individual subregion sectoral earnings have generally followed the same patterns as the overall SERC region sectotal earnings. The VACAR subregion had the highest regional earnings totals, with a large government sector earnings value. The SOUTHERN subregion had the second highest regional earnings value. The TVA subregion had the lowest total earnings of the four subregions.

Per capita income in SERC has been increasing at the average annual rate of 3.5 percent. The 1970 SERC per capita income of 3,002 dollars was 86 percent of the national average. Although the SERC Region per capita income was much lower than the national average, the disparity has been decreasing. The 1970 per capita income of the VACAR and FLORIDA subregions was higher than the SERC average. The per capita income of the TVA and SOUTHERN subregions was lower than the SERC average.

Peak Demand

Exhibit VII-3 gives the historical annual energy, peak demand and load factor of SERC for the years 1960, 1965, 1970, and 1973 through 1977. Also included in Exhibit VII-3 are annual growth rates of annual energy and peak demand.

The VACAR subregion and the SOUTHERN subregion have their highest peak-hour demand in summer. The TVA subregion and the FLORIDA subregion have it in winter, although the energy use in Florida is largest in the summer.

For the total SERC region, the peak-hour demand increased by 7.7% from 1976 to 1977, compared to an annual increase of 3.3% for 1976, 3.3% for 1975, and 2.8% for 1974. This corresponds to an average annual growth rate of 4.3% over the 1973-1977 period. In 1977, the highest peak-hour demand was 79,924 MW in January. The summer peak-hour demand was 79,332 MW in July.

Table VII-4 gives the annual energy, peak demand and load factor for the main electric utilities in each subregion of SERC.

Energy Demand

Exhibit VII-3 gives the historical annual energy. The annual growth rate of energy in SERC was 6.8% from 1976 to 1977, compared to an annual increase of 6.2% for 1975-1976, 2.3% for 1974-1975 and a decrease of 0.4% for 1973-1974. This corresponds to an average annual growth rate of 3.7% over the 1973-1977 period. In 1977, the annual energy was 442,233 GWh.

Exhibit VII-4 gives the annual growth rates of energy consumption by consumer categories for representative electric systems in each subregion of SERC for the years 1971 to 1977. These categories are residential, commercial, and industrial. The growth rates of the total energy consumption by these three categories are also given.

Table VII-5 gives the 1977 energy consumption by consumer categories for representative utilities in each subregion of SERC.

Load Characteristics

Exhibit VII-3 gives the load factor of SERC for the years 1960, 1965, 1970, and 1973 through 1977. In 1977, the annual load factor was 63.2%. Table VII-3 shows the load factors for representative electric utilities in each subregion. Exhibit VII-5 gives weekly load factors during the first week of April, August and December 1977 for representative electric utilities. The magnitude of the weekly peak load demand and the date of its occurrence are also given. Weekly load duration curves for representative utilities are shown in Exhibit VII-6.

The SERC region has summer and winter peaking systems. There are great variations in the annual load factor, but most of them ranged between 50 and 65 percent during 1977.

Table VII-6 gives the monthly energy and peak demand during the twelve months of 1977 for the four subregions of SERC.

Table VII-4

SERC
ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR
1977

Representative Utilities	Annual Energy GWh	Peak Demand MW	Month of Peak Demand	Load Factor %
VACAR				
- Duke Power Company	51,240	9,450	January	61.9
- Virginia Electric Power Company	37,981	7,902	July	54.9
- Carolina Power & Light Company	28,939	5,597	July	59.0
TVA				
- Tennessee Valley Authority	124,618	21,803	January	78.4
SOUTHERN				
- Alabama Power Company	1,134	243	July	53.3
- Southern Company System 1/	93,897	7,956	July	59.7
- Savannah Electric & Power Company	2,291	447	July	58.6
FLORIDA				
- Florida Power & Light Company	40,712	8,606	January	54.0
- Florida Power Corporation	17,150	3,899	January	50.2
- Tampa Electric Company	10,131	1,784	January	64.8

1/ Includes Alabama Power Company, Georgia Power Company and Mississippi Power Company.

Reference: [VII-4]

Table VII-5

SERC
ENERGY CONSUMPTION BY CONSUMER CATEGORIES
1977 - (Percent of Total)

	Residential	Commercial	Industrial	Others	Sale For Resale	Total
VACAR						
- Duke Power Company	25.5	17.7	39.3	17.5	-	100.0
- Virginia Electric & Power Company	33.5	24.7	17.0	24.8	-	100.0
TVA						
- Tennessee Valley Authority	32.0	28.7	19.3	20.0	-	100.0
SOUTHERN						
- Alabama Power Company	29.5	17.2	43.0	8.3	2.0	100.0
- Gulf Power Company	39.9	22.3	27.6	10.2	-	100.0
- Mississippi Power Company	22.3	18.4	39.7	1.1	18.5	100.0
FLORIDA						
- Florida Power & Light Company	50.9	34.3	7.3	2.1	5.4	100.0
- Florida Power Corporation	40.0	22.1	17.7	20.2	-	100.0
- Tampa Electric Company	32.7	19.8	41.7	5.8	-	100.0

Source: 1977 Annual Reports of the above listed Utilities.

Table VII-6

SERC
MONTHLY ENERGY, PEAK DEMAND AND LOAD FACTOR - 1977

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	1977
VACAR													
Peak Hour Demand-MW	25,055	23,148	19,798	18,225	20,263	23,735	26,425	25,541	23,895	19,363	20,862	23,490	26,425
Net Energy-GWH	13,843	10,757	10,456	9,688	10,530	11,358	13,103	13,175	11,448	10,418	10,706	12,288	137,770
Load Factor, %	74.3	69.1	71.0	73.8	69.8	66.5	66.6	69.3	66.5	72.3	71.3	70.3	59.5
TVA													
Peak Hour Demand-MW	21,803	19,856	18,020	16,861	17,499	18,345	18,953	18,833	18,430	17,142	17,855	20,733	21,803
Net Energy-GWH	12,836	10,424	9,891	9,422	10,224	10,492	11,129	10,998	9,807	9,898	9,899	11,313	126,333
Load Factor, %	79.1	78.1	73.8	77.6	78.5	79.4	78.9	78.5	73.9	77.6	77.0	73.3	66.1
SOUTHERN													
Peak Hour Demand-MW	16,232	14,991	13,220	12,795	16,234	18,398	18,771	18,357	17,483	13,642	13,164	14,861	18,771
Net Energy-GWH	8,918	7,117	7,222	6,926	7,944	9,296	9,844	9,848	8,618	7,379	7,128	7,993	98,233
Load Factor, %	73.8	70.6	73.4	75.2	65.8	70.2	70.5	72.1	68.5	72.7	75.2	72.3	59.7
FLORIDA													
Peak Hour Demand-MW	16,834	15,026	12,625	11,727	12,384	15,343	15,183	14,646	14,896	13,673	11,504	14,777	16,834
Net Energy-GWH	7,337	5,779	6,052	5,820	6,008	7,594	7,772	7,790	7,529	6,067	5,749	6,400	79,897
Load Factor, %	58.6	57.2	64.4	68.9	65.2	68.7	68.8	71.5	70.2	59.6	69.4	58.2	54.2
SERC REGION													
Peak Hour Demand-MW	79,924	73,021	63,663	59,608	66,380	75,821	79,332	77,377	74,704	63,820	63,385	73,861	79,924
Net Energy-GWH	42,934	34,077	33,621	31,856	34,706	38,740	41,848	41,811	37,402	33,762	33,482	37,994	442,233
Load Factor, %	72.2	69.4	71.0	74.2	70.3	71.0	71.0	72.6	69.5	71.1	73.4	69.1	63.2

Reference: [VII-2]

Regional Electric Power Supply

Existing Generating Facilities

Exhibit VII-7 shows the winter generating capability by type of plants for the members and non-members of the four subregions. Table VII-7 gives the total summer and winter generating capability for the SERC region and for the four subregions. The winter generating capability by type of plants is also shown in Table VII-7.

Except for FLORIDA, the SERC subregions rely predominantly on coal. In the FLORIDA subregion, oil is the main fuel, although recently announced plants will burn coal.

Current Role of Hydropower

Hydropower, including conventional hydroelectric and pumped storage units, represents about 9.5% of the SERC 1977 generating capability, as compared to about 12% for the 1977 national average. Table VII-8 gives the hydropower capability in SERC and its subregions, as reported in the SERC report [VII-2].

In the VACAR subregion, the only pumped storage plant is Jocassee. Its capability is 610 MW and represents 1.8% of the total generating capability in VACAR. There are many conventional hydroelectric plants totaling 2,463 MW.

In the TVA subregion, there are no pumped storage plants operating, although Racoon Mountain with 1,500 MW is under construction. Conventional hydro represents 15.5% of the total generating capability. Tennessee Valley Authority has a capability of 2,948 MW from a multitude of plants.

In the SOUTHERN subregion, Carters plant has a total capability of 556 MW, half of which is pumped storage and the other half is convetional. Conventional hydro represents 11.4% of the total generating capability in SOUTHERN. Georgia Power Company, Alabama Power Company and Southeastern Power Administration (as marketing agent for the Corps of Engineers) are the principal electric utilities with conventional hydroelectric plants.

Table VII-7

SERC
GENERATING CAPABILITY
1977

		SERC	VACAR	TVA	SOUTHERN	FLORIDA
Summer Capability	MW	105,254	33,251	26,155	24,228	21,620
Winter Capability	MW	106,901	33,887	26,274	24,127	22,613
Generation in Winter (Percentage)						
Nuclear		13.2	18.9	12.5	6.5	13.1
Steam Turbine						
Gas		0.2	-	-	0.4	0.3
Coal		48.9	50.7	64.6	68.4	9.2
Oil		17.2	12.6	-	5.8	56.2
Combined Cycle		0.6	1.3	-	-	1.3
Hydroelectric		8.7	7.3	15.5	11.4	-
Pumped Storage		0.8	1.8	-	1.2	-
Combustion Turbine						
Gas		0.1	-	-	0.3	-
Oil		9.0	3.7	9.4	6.0	19.4
Internal Combustion						
Oil		1.3	3.7	-	-	0.5
TOTAL		100.0	100.0	100.0	100.0	100.0

Reference: [VII-2]

Table VII-8

SERC
HYDROPOWER CAPABILITY[1/]
As of January 1, 1978 - MW

	Conventional Hydro	Pumped Storage
VACAR		
- Carolina Power & Light Company	212	-
- Duke Power Company	842	610
- Southeastern Power Administration	515	-
- South Carolina Public Service Authority	124	-
- South Carolina Electric & Gas Company	244	-
- Virginia Electric Power Company	326	-
- Yadkin, Inc.	200	-
TVA		
- Tennessee Valley Authority	2,948	-
- Southeastern Power Administration	704	-
- Tapco, Inc.	316	-
- Nantahala Power & Light	92	-
SOUTHERN		
- Alabama Electric Cooperative	4	-
- Alambama Power Company	1,139	-
- Crisp County Power Commission	13	-
- Georgia Power Company	456	-
- Southeastern Power Administration	1,141	278
FLORIDA		
- Southestern Power Administration	30	-
SERC	9,276	888

Reference: [VII-2]
1/ Based on winter generating capability.

In the FLORIDA subregion there is only one federal conventional hydropower plant: Jim Woodruff (30 MW). Table VII-9 shows the ownership and the magnitude of the hydroelectric power in the existing systems within each subregion.

Load Resource Analysis

The SERC region has both summer and winter peaking systems. The generating reserve margin varies between 18 and 33 percent of the demand requirements for the four subregions. For the total SERC region, it averages 24.7% as compared to 22.9% for VACAR, 20.2% for TVA, 27.3% for SOUTHERN and 30.4% for FLORIDA.

Table VII-10 gives a detailed load resource balance for the SERC region and the four subregions.

For 1978, SERC is expected to be a net exporter of 1,488 MW during the summer, and a net importer of 1,433 MW during the winter. In addition, SERC has interchange of emergency, short term, diversity, and economy power with adjoining systems. Current emergency capabilities between SERC and surrounding reliability councils are shown in Table VII-11.

Table VII-9

SERC
OWNERSHIP OF HYDROPOWER 1/
As of January 1, 1978

	Investor Owned	Cooperative	State	Federal	Total
SERC					
No. of Utilities	10	1	2	5	18
Capability, MW					
Conventional Hydro	3,827	4	137	5,308	9,276
Pumped Storage	610	-	-	278	888
Total, MW	4,437	4	137	5,586	10,164
%	43.7	0.0	1.3	55.0	100.0
VACAR					
No. of Utilities	6	-	1	1	8
Capability, MW					
Conventional Hydro	1,824	-	124	515	2,463
Pumped Storage	610	-	-	-	610
Total, MW	2,434	-	124	515	3,073
%	79.2	-	4.0	16.8	100.0
TVA					
No. of Utilities	2	-	-	2	4
Capability, MW					
Conventional Hydro	408	-	-	3,652	4,060
Pumped Storage	-	-	-	-	-
Total, MW	408	-	-	3,652	4,060
%	10.0	-	-	90.0	100.0
SOUTHERN					
No. of Utilities	2	1	1	5	5
Capability, MW					
Conventional Hydro	1,595	4	13	1,141	2,753
Pumped Storage	-	-	-	-	-
Total, MW	1,595	4	13	1,141	2,753
%	57.9	0.1	0.5	41.5	100.0
FLORIDA					
No. of Utilities	-	-	-	1	1
Capability, MW					
Conventional Hydro	-	-	-	30	30
Pumped Storage	-	-	-	-	-
Total, MW	-	-	-	30	30
%	-	-	-	100.0	100.0

Reference: [VII-2].

Note: The above capabilities are reported to SERC by the utilities. In addition, capability of small, unreported plants are approximately as follows: 39 MW Industrial, 14 MW Investor-owned, 30 MW Federal and 23 MW Publically-owned (non-Federal); Total 106 MW.

1/ Based on winter capability.

Table VII-10

SERC
RESOURCES, DEMAND & MARGIN PROJECTED FOR 1978

	SERC		VACAR		TVA		SOUTHERN		FLORIDA	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
RESOURCES IN MW										
Net Dependable Capability	110,243	112,233	34,535	35,190	27,280	27,399	26,035	26,169	22,393	23,475
All Scheduled Imports	675	2,135	300	0	0	2,060	375	75	0	0
All Schedule Exports	2,163	702	75	375	2,060	0	0	300	28	27
Total Resources	108,755	113,666	34,760	34,815	25,220	29,459	26,410	25,944	22,365	23,448
Inoperable Capability	0	0	0	0	0	0	0	0	0	0
Operable Resources	108,755	113,666	34,760	34,815	25,220	29,459	26,410	25,944	22,365	23,448
DEMAND IN MW										
Peak Hour Demand	84,400	86,885	27,262	26,680	20,150	23,950	20,756	18,944	16,232	17,311
Interruptible Demand	100	100	100	100	0	0	0	0	0	0
Demand Requirements	84,300	86,785	27,162	26,580	20,150	23,950	20,756	18,944	16,232	17,311
MARGIN IN MW										
Margin	24,455	26,881	7,598	8,235	5,070	5,509	5,654	7,000	6,133	6,137
Scheduled Outage	2,213	6,895	799	2,705	629	1,077	0	1,800	785	1,313
Adjusted Margin	22,242	19,986	6,799	5,530	4,441	4,432	5,654	5,200	5,348	4,824
Percent of Demand Requirements	26.4	23.0	25.0	20.8	22.0	18.5	27.2	27.4	32.9	27.9
Percent of Operable Resources	20.5	17.6	19.6	15.9	17.6	15.0	21.4	20.0	23.9	20.6

Reference; [VII-2]

Table VII-11

SERC
EMERGENCY TRANSFER CAPABILITIES - MW
BETWEEN RELIABILITY COUNCILS
1978

From:		To:
SERC (TVA)	1,500	ECAR
ECAR	2,500	SERC (TVA)
SERC (VACAR)	2,400	ECAR
ECAR	1,350	SERC (VACAR)
SERC (VACAR)	2,700	MAAC
MAAC	1,050	SERC (VACAR)
SERC (TVA)	2,500	MAIN
MAIN	3,000	SERC (VACAR)
SERC	4,000	SWPP
SWPP	3,500	SERC

Reference: [VII-3]

REFERENCES

VII-1 National Electric Reliability Council, 1977 National Report.

VII-2 SERC, "Coordinated Bulk Power Supply Program," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

VII-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," August, 1978.

VII-4 Federal Power Commission, "FPC Form 12," Washington, D.C. 1977.

VII-5 U.S. Water Resources Council, "1972, OBERS Projections," Volume 1-2, Washington, D.C., April, 1974.

Chapter VIII

SOUTHWEST POWER POOL
SWPP

Introduction

This chapter presents an overview of the electric power systems which are bulk power suppliers in the Southwest Power Pool (SWPP). The regional electric power demand and supply are also presented.

Regional Power System

Delineation of Region

The SWPP boundaries are shown on Exhibit I-1. The SWPP region includes all of the states of Arkansas, Kansas, Louisiana and Oklahoma, and part of the states of Mississippi, Missouri, New Mexico, and Texas. In this study, SWPP is considered as one study region, there is no division into sub-regions.

Ownership

The bulk power system members and non-members of SWPP are shown on Exhibit VIII-2 [VIII-1][3/]. Plant ownership in the SWPP is primarily investor-owned and municipal. The breakdown by number of utilities, and summer capability is shown in Table VIII-1. The total 1977 generating capability in SWPP was 43,692 MW in the winter and 43,892 MW in the summer.

Table VIII-1

SWPP

OWNERSHIP OF GENERATION SOURCES[1/]
AS OF JANUARY 1, 1978

	Investor-Owned	Cooper-ative	Munic-ipal	State	Fed-eral[2/]	Total
Number of Utilities	16	4	1	13	1	35
Capability						
MW	37,528	1,505	2,218	509	2,132	43,892
% of Total	85.5	3.4	5.0	1.2	4.9	100.0

1/ Based on summer capability.
2/ Marketing Agency.

3/ Numbers in brackets refer to references listed at end of Chapter.

Transmission System

The SWPP maintains an extensive network of transmission facilities. Table VIII-2 shows the mileage of existing 230, 345, and 500 kV transmission lines in SWPP [VIII-2].

Table VIII-2

SWPP

TRANSMISSION LINES
AS OF JANUARY 1, 1978

Voltage kV	Circuit miles
230	2,791
345	2,172
500	1,363

Power Exchanges and Interties between Regions

SWPP has interties with three neighboring councils:

MAIN - Mid-America Interpool Network
MARCA - Mid-Continent Area Reliability Council
SERC - Southeastern Electric Reliability Council

There exits power exchanges between systems within SWPP and the neighboring councils. The net amount of energy exchanged between these councils during 1977 is as follows:

From			To
MAIN	882,595	Net MWh	SWPP
MARCA	668,848	Net MWh	SWPP
SWPP	659,613	Net MWh	SERC

Possibilities of new interconnections between systems in SWPP and SERC have been investigated. Interconnections between SWPP and ERCOT could be beneficial to SWPP and its interfacing systems. Further interconnection and exchange of power between systems in SWPP and MARCA have also been studied [VIII-5].

Regional Electric Power Demand

Socio-Economic Conditions

Table VIII-3 summarizes the significant 1970 economic and demographic indicators for SWPP. The economic and demographic data on SWPP were obtained from the BEA areas corresponding reasonably close, but not exactly with SWPP boundaries. A map showing the SWPP region as approximated by the BEA areas is given on Exhibit I-2. A list of the BEA areas within SWPP appears on Exhibit I-3.

Table VIII-3

SWPP
ECONOMIC INDICATORS
1970

Sector Earnings (Million $)1/	
Agriculture	2,510
Mining	996
Construction	2,086
Manufacturing	6,978
Transportation Utilities	2,774
Trade	5,575
Finance	1,438
Services	4,452
Government	5,697
Total Earnings (Million $)1/	32,639
Population (1,000)	14,689
Per Capita Income ($)1/	2,879
Relative to U.S.	.828

Notes: (1) SWPP Region approximated by BEA Areas 109, 110, 111, 115, 116, 117, 118, 119, 120, 122, 130, 131, 132, 133, 134, 135, 138, 139, 140.

(2) The sum of sector earning does not equal the total because some data for individual BEA sector earnings was deleted to avoid disclosure of data pertaining to a particular establishment.

(3) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.
Reference: [VIII-4]

The population in the SWPP region has been increasing at an average annual rate of about 0.7 percent. The 1970 SWPP population of 14.7 million represented about 7.2 percent of the national total. The SWPP portion of national population has been decreasing since 1950.

The total earnings in the SWPP region accounted for 5.8 percent of the 1970 national earnings. The SWPP share of national earnings has been decreasing since 1950. However, earnings within SWPP have been growing at an annual rate of about 3.7 percent since 1950. The SWPP manufacturing sector earnings have been growing at about 5 percent annually since 1950. In 1970, the manufacturing sector produced 21 percent of the SWPP total earnings.

The government, trade, and service sectors also produced significant portions of the 1970 SWPP earnings. Agriculture and mining were important in this area, since they contributed large shares to the national markets. The SWPP based agriculture and mining industries each contributed about 13 and 18 percent to their respective national sector earnings totals.

The disparity between national and SWPP per capita income has been decreasing during the period 1950 to 1970. During 1950, the SWPP per capita income of $1,571 was only 76 percent of the national average. During 1970, the per capita income increased to $2879, about 83 percent of the national average. The average annual growth rate of per capita income was 3.1 percent between 1950 and 1970.

Peak Demand

Exhibit VIII-3 gives the historical annual energy, peak demand, and load factor of SWPP for 1970 through 1977. Also included in Exhibit VIII-3 are annual growth rates and average compound annual growth rates for 5-year periods of annual energy and peak demand.

The peak demand in SWPP increased at an average annual growth rate of about 9.8% over the 1970-1975 period from 20.1 GW in 1970 to 32.2 GW in 1975. The annual growth rate is only 0.4% for 1974-1975. The peak demand continued to grow at a higher rate after 1975; the annual growth rate was 4.9% for 1975-1976 and 9.1% for 1976-1977.

Energy Demand

The annual demand for electric energy in SWPP increased from about 98,800 GWh in 1970 to 154,200 GWh in 1975. This corresponds to an average annual compounded growth rate of about 9.3% over the 1970 level. The demand continued to rise at a growth rate of 4.9% for 1975-1976 and 11.0% for 1976-1977. The annual energy demand in 1977 reached 179,500 GWh.

Annual growth rates of energy consumption by consumer categories for representative electric systems in SWPP are given in Exhibit VIII-4 for the years 1968 to 1977. Table VIII-4 shows the 1977 consumer consumption breakdown for six representative utilities in SWPP.

Load Characteristics

Since 1970, the annual load factor in SWPP has been relatively constant. In 1977 it was 55.6 percent as shown in Exhibit VIII-3. Exhibit VIII-5 shows the weekly load factors for the first week of April, August, and December 1977 for representative utilities in SWPP. The magnitude of the weekly peak load demand and the date of its occurrence are also given. SWPP has both summer and winter peaking systems, but nearly all of the major systems have a summer peak. Weekly load curves and load duration curves for representative utilities are shown in Exhibit VIII-6. Energy, peak demand and load factor for the 12 months of 1977 is shown in Table VIII-5.

Regional Electric Power Supply

Existing Generating Facilities

The existing generating capability of SWPP as of January 1, 1978 is about 43,900 MW in summer and 43,700 MW in winter. The breakdown by types of plants for winter generating capability is shown in Table VIII-6. Natural gas-fired steam turbine plants provide the bulk of the generating capability in SWPP. Exhibit VIII-7 gives the generating capability by types of plants of bulk power systems in SWPP.

Table VIII-4

SWPP

ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percent of Total)
1977

Utility	Residential	Commercial	Industrial	Sales to Other Utilities	Other	Total
Gulf States Utilities Co.	20.3	14.8	56.2	-	8.7 1/	100.0
Kansas City Power & Light Co.	28.9	39.0	27.2	4.0	0.9	100.0
Southwestern Public Service Co.	14.0	17.0	44.0	25.0 1/	-	100.0
Central Louisiana Electric Co., Inc.	32.6	12.6	32.0	16.7	6.1	100.0
Kansas Gas & Electric Co.	27.2	20.4	37.8	13.6	1.0	100.0
The Board of Public Utilities of Kansas City	19.7	28.3	44.4	-	7.6 1/	100.0

1/ Sales to other utilities and "other" are included in these figures.

Table VIII-5
SWPP
MONTHLY ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Month	Peak Hour Demand-GW	Net Energy GWh	Load Factor - %
January	25,315	14,679	75.5
February	23,315	12,325	78.7
March	22,529	12,830	76.5
April	22,749	12,500	76.3
May	28,950	14,525	67.4
June	33,439	17,319	71.9
July	36,514	19,297	68.8
August	35,644	18,386	67.2
September	33,037	16,576	69.7
October	26,816	13,637	68.4
November	23,845	13,157	76.6
December	25,226	14,318	76.3

Reference: [VIII-8]

Table VIII-6

SWPP

GENERATING CAPABILITY BY TYPE OF PLANT
AS OF JANUARY 1, 1978

	Summer		Winter	
	MW	Percent	MW	Percent
Nuclear	836	1.9	836	1.9
Steam Turbine				
Gas	28,009	63.9	27,842	63.7
Coal	5,200	11.8	4,931	11.3
Oil	3,848	8.8	3,848	8.8
Combined Cycle	1,509	3.4	1,541	3.5
Conventional Hydro	2,207	5.0	2,218	5.1
Pumped Storage	288	0.7	288	0.7
Combustion Turbine				
Gas	496	1.1	512	1.2
Oil	1,320	3.0	1,491	3.4
Internal Combustion				
Gas	45	0.1	45	0.1
Oil	92	0.2	92	0.2
Other	42	0.1	48	0.1
TOTAL	43,892	100.0	43,692	100.0

Current Role of Hydropower

At the present time, hydroelectric power comprises 5.7 percent of the total SWPP generating capability. This relatively small portion is maintained by four member utilities in SWPP. The Grand River Dam Authority (GRRD) has 210 MW of conventional hydro and 260 MW of pumped storage capability. Together, these sources provide 90% of GRDD's generating capability. Middle South Utilities, Inc. (MSUI) has 69 MW of conventional hydropower, less than 1% of its total generating capability. The Southwestern Power Administration (SWPA) markets the largest block of hydropower in SWPP, supplying 1923 MW of conventional hydropower and 28 MW of pumped storage. This mix represents 92% of SWPA's total generating capability. The smallest hydropower producer is the Empire District Electric Company, supplying 16.0 MW (4% of its total capability) of conventional hydropower.

The ownership of hydropower in SWPP is shown in Table VIII-7. Harry Truman pumped-storage project is scheduled to be in operation starting in March 1979. When completed, Harry Truman plant will have a total capacity of 162 MW. The Clarence Cannon Project is also under construction and is scheduled to be in operation by August 1980 (27 MW conventional and 31 MW pumped storage).

Table VIII-7

SWPP

OWNERSHIP OF HYDROPOWER
AS OF JANUARY 1, 1978

	Investor-Owned	State	Federal 1/	Total
Number of Utilities	2	1	1	4
Summer Capability, MW				
Conventional	85	210	1,923	2,218
Pumped Storage	-	260	28	288
Total	85	470	1,951	2,506
Capability, %	3.4	18.8	77.8	100.0

Note: The above are plants reported to DOE by Reliability Councils. In addition, small unreported plants (primarily industrial and municipal) are approximately 84 MW; 81 MW at Toledo Ben and 3 MW at Niangro.

1/ Marketing Agency.

Load Resource Analysis

Demand-Supply Balance

The load resource balance projected by SWPP for 1978 is shown in Table VIII-8.

Table VIII-8

SWPP
RESOURCES, DEMAND & MARGIN
Projected for 1978

	Summer Peak	Winter peak
Resources in MW		
Net Capability	46,487	47,109
Scheduled Imports	5,411	3,869
Scheduled Exports	3,704	5,062
Total Resource	48,194	45,916
Inoperable Capability	134	133
Operable Resources	48,059	45,783
Demand in MW		
Peak Hour Demand	38,946	27,810
Interruptible Demand	0	0
Demand Requirements	38,946	27,810
Margin in MW		
Margin	9,113	17,969
Scheduled Outage	44	3,981
Adjusted Margin	9,069	13,988
Percentage of Demand Requirements	23.3	50.3
Percentage of Operable Resources	18.9	30.6

Imports and Exports

Scheduled imports and exports for SWPP in 1978 are shown in Table VIII-8. During the 1978 summer peak, scheduled imports and exports are 5,411 and 3,704 MW, respectively. The scheduled imports and exports for the 1978 winter peak are 3,869 MW and 5,062 MW, respectively. The SWPP is expected to be a net importer of power in the summer season, and a net exporter in the winter season [VIII-1].

Emergency transfer capabilities, in terms of power, are as shown in Table VIII-9.

Table VIII-9

SWPP

EMERGENCY TRANSFER CAPABILITIES
BETWEEN RELIABIILITY COUNCILS
SUMMER, 1978

From	Transfer Capability MW	To
SWPP	1,100	MARCA
MARCA	1,150	SWPP
SWPP	2,000	MAIN
MAIN	1,400	SWPP
SWPP	3,500	SERC
SERC	4,000	SWPP

Reserve Margins and Regional System Reliability

The reserve margins for summer and winter peaks in 1978 are shown in Table VIII-8.

The SWPP has established planning criteria to help ensure the electrical reliability of the region. In terms of generating capacity, the capacity available in SWPP is planned to exceed the predicted annual peak load obligation by a margin of 15 percent [VIII-1].

LIST OF REFERENCES

VIII-1 "Southwest Power Pool, Coordinated Regional Bulk Power Supply Programs 1978-1997," Report to the Economic Regulatory Administration, Department of Energy, April 1, 1978.

VIII-2 "Eighth Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems", National Electric Reliability Council, August 1978.

VIII-3 "National Electric Reliability Council 1977 Annual Report," March 1978.

VIII-4 U.S. Department of Commerce, Bureau of Economic Analysis," 1972 OBERS Projections, Regional Economic Acitivity in the United States," Series E Population, U.S. G.P.O., Washington, D.C., April 14, 1978.

VIII-5 SWPP, "Report to National Electric Reliability Council," 1977.

Chapter IX

ELECTRIC RELIABILITY COUNCIL OF TEXAS
ERCOT

Introduction

This chapter describes the Electric Reliability Council of Texas (ERCOT). The regional power systems, electric power demand and supply, and load resource balance are presented.

Regional Power System

Delineation of the Region

As one of the regional councils of NERC, ERCOT was formally organized in 1970 in conformity with the aims and objectives of NERC. Exhibit I-1 shows its boundaries with the other council areas. The ERCOT Region includes most of the State of Texas. The area is approximately 195,000 square miles, or 73% of the state. The ERCOT system operates within Texas and comprises 85% of the total electric generation located in the state. Approximately nine million people are served by the member systems in ERCOT [IX-1][1/].

Before May 1977, ERCOT consisted of two interconnected groups operating as separate systems, with one group being interstate, and the other being intrastate. But since May 1977 ERCOT has operated as one interconnected system.

Ownership

Membership in the Council is available on a voluntary basis to any Texas utility engaged in the generation, transmission or distribution of electric power. The present membership consists of 27 muncipalities, 50 cooperatives, 1 state agency, and 8 investor-owned companies.

Exhibit IX-2 gives the list of the reporting and non-reporting members of the Council. The non-reporting members have a generating capability less than 25 MW.

Table IX-1 summarizes the generating capability by ownership categories for all the reporting utilities of ERCOT. The summer and winter generating capabilities are the same.

1/ Numbers in brackets refere to references listed at the end of this chapter.

Table IX-1

ERCOT

Ownership of Generation Sources
As of January 1, 1978

		Investor-Owned	Muni-cipal	Cooper-ative	State	Total
ERCOT Region		6	6	3	1	16
Capability	MW	30,161	4,940	648	1,280	37,029
	%	81.5	13.3	1.7	3.5	100.0

Reference [IX-2]

Transmission System

Historically, the bulk power transmission network of ERCOT has had nearly 30 years experience operating as an interconnected system. The accepted philsosophy has been that each system contributing to the network provides adequate generation to serve its own peak load and carry its share of the reserves.

As of January 1, 1978, there are 3,657 circuit-miles of 345-kV transmission lines in use.

The operating systems of ERCOT are divided into seven control areas, each of which maintains a control center. These control centers are interconnected to two security centers, one in the North, one in the South, whose functions are to assemble daily load capability data, and issue normal and emergency operating instructions to the control centers of the ERCOT system.

Power Exchange and Interties between Regions

The ERCOT systems originally comprised an interconnected group that had no transmission interconnections with any other council region, supplying power only within a large part of the State of Texas. On May 4, 1976 the West Texas Utilities Company (WETU), an ERCOT member, began furnishing power to three Oklahoma localities and, for a short time, thereby became an interstate utility. Some ERCOT systems elected to remain intrastate utilities and opened their interconnections with the interstate system. As a result ERCOT was divided into an "intrastate group" and an "interstate group." However, in May 1977, an order of the Public Utilities Commission of Texas required all the ERCOT system to return to the intrastate interconnected status that existed on May 3, 1976. A single report was filed by ERCOT under Order 383-4 on April 1, 1977. The 1978 report [IX-2] treats ERCOT as a single network isolated from utilities in other Reliability Council Regions. There is a transmission line connection to SWPP, however, the circuit is open and this line is not used.

Regional Electric Power Demand

Socio-Economic Conditions

Table IX-2 shows population, earnings and income originating in the ERCOT region for year 1970. The economic and demographic data on ERCOT were obtained from the BEA areas corresponding reasonably close, but not exactly with ERCOT boundaries. A map showing the ERCOT region as approximated by BEA areas is given on Exhibit I-2. A list of BEA areas within ERCOT appears on Exhibit I-3.

Between the years 1950 and 1970, the population within ERCOT has been increasing at an average annual rate of about 2.0 percent. The ERCOT population growth has been higher than the national rate of 1.5 percent. In 1970, the ERCOT region population was about 5 percent of the national total.

Table IX-2

ERCOT
ECONOMIC INDICATORS
1970

Sector Earnings (Million $) 1/	
Agriculture	1,379
Mining	828
Construction	1,660
Manufacturing	4,754
Transportation Utilities	1,753
Trade	4,570
Finance	1,309
Services	3,636
Government	4,911
Total Earnings (Million $) 1/	24,800
Total Population (Thousand)	9,706
Per Capita Income ($) 1/	3,202
Per Capita Income Relative to U.S.	921

NOTE: (1) ERCOT Region is approximated by BEA Areas: 121, 123, 124, 125, 126, 127, 128, 129, 141, 142, 143, 144.

(2) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Reference: [IX-5]

The total earning origninating in the ERCOT region was increasing at about 4.6 percent annually between the years 1950 and 1970. The ERCOT region share of national earnings has been increasing since 1950. In 1970 the earnings from ERCOT represented 4.4 percent of the national total. In terms of dollars, the manufacturing, trade and government sectors have contributed most to the ERCOT region total earnings. Mining earnings are only 3 percent of the total 1970 ERCOT earnings, but represent about 14 percent of the national mining earnings. The 1970 agriculture earnings from ERCOT represents 7 percent of the national agriculture earnings.

The ERCOT region per capita income is slightly lower than the national average. However, in 1979, the per capita income relative to the U.S. was the highest since 1950. The per capita income is increasing at an average annual rate 2.7 percent.

Peak Demand

Exhibit IX-3 gives the historical annual energy, peak demand, and load factor of ERCOT for the years 1965, 1970, and 1973 through 1977. Also included in Exhibit IX-3 are annual growth rates of annual energy and peak demand.

The peak-hour demand increased by 6.5% from 1976 to 1977, compared to an annual increase of 8.8% for 1976, 0.4% for 1975, and 11.6% for 1974. This corresponds to an average annual growth rate of 6.8% over the 1973-1977 period. In 1977 the highest peak-hour demand was 26,819 MW, in August. The winter peak demand was only 18,115 MW, in January.

Table IX-3 gives the annual energy, peak demand, and load factor for representative electric systems of ERCOT. The peak demand is in the summer.

Table IX-3

ERCOT
ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Representative Utilities	Annual Energy GWh	Peak Demand MW	Month of Peak Demand	Annual Load Factor, %
Houston Lighting & Power Co.	48,524	8,645	July	64.1
Texas Power & Light Co.	23,440	4,754	August	56.3
Texas Electric Service Co.	18,648	3,594	July	75.0
Dallas Power & Light Co.	11,138	2,495	August	51.0
Central Power & Light Co.	12,106	2,320	August	59.6

Reference: [IX-4]

Energy Demand

As shown in Exhibit IX-3 the annual growth rate of energy in ERCOT was 11.6% from 1976 to 1977, compared to an annual increase of 5.4% for 1975-1976, 6.7% for 1974-1975, and 3.0% for 1973-1974. This corresponds to an average annual growth rate of 6.7% over the 1973-1977 period. In 1977, the annual net energy was 136,413 GWh.

Load Characteristics

Exhibit IX-3 gives the annual load factor of ERCOT for the years 1965, 1970, and 1973 through 1977. In 1977, the annual load factor was 58.1%. Table IX-3 shows the annual load factors for representative electric utilities in ERCOT.

Exhibit IX-4 shows the weekly load factors for the first week of April, August, and December 1977 for representative utilities in ERCOT. The magnitude of the weekly peak load demand and the date of occurrence are also given. Exhibit IX-5 presents the weekly load curves during the first weeks of April, August, and December, 1977. The ERCOT region has a summer peak, and most of the monthly load factors ranged between 50 and 65 percent during 1977.

Table IX-4 gives the energy, peak demand and load factor for the 12 months of 1977.

Table IX-4

ERCOT
MONTHLY ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Month	Peak Hour Demand-MW	Net Energy GWh	Load Factor
January	18,115	10,523	78.1
February	16,956	8,690	76.5
March	16,457	9,535	78.1
April	17,178	9,301	75.5
May	22,318	11,329	68.3
June	24,656	13,346	75.3
July	26,407	14,694	74.8
August	26,819	14,952	75.0
September	26,230	13,593	72.1
October	23,476	10,788	61.7
November	18,085	9,594	73.6
December	17,950	10,068	75.6
1977	26,819	136,413	58.1

Reference: [IX-2]

Regional Electric Power Supply

Existing Generating Facilities

Exhibit IX-6 shows the generating capability by type of plants for each reporting member of ERCOT. Table IX-5 summarizes the total generating capability by type of plants for ERCOT.

Table IX-5

ERCOT
GENERATING CAPABILITY BY TYPE OF PLANTS 1/
As of January 1, 1978

	MW	%
Steam Turbine		
Gas	30,964	83.6
Coal	4,127	11.1
Combined Cycle	542	1.5
Hydroelectric 2/	230	0.6
Combustion Turbine		
Gas	1,053	2.8
Oil	50	0.2
Internal Combustion		
Gas	37	0.1
Oil	26	0.1
Total	37,029	100.0

1/ Summer and winter capability are the same.
2/ Includes only ERCOT members.

Reference: [IX-2]

ERCOT relies predominately on natural gas to supply its power and energy needs. The total generating capability for summer and winter is 37,029 MW of which 86.5% is from natural gas. The second main fuel used in ERCOT is coal. It provides 11.1% of the generating capability.

Current Role of Hydropower

The total hydropower installation in Texas is 543 MW. However, ERCOT reports that hydropower represents 230 MW, or 0.6% of the ERCOT system generating capability. These facilities all are conventional hydroelectric plants. Buchanan is the only plant having pumped storage capability. The size of the hydroelectric plants range from 0.25 to 84 MW. Table IX-6 gives the list of the hydroelectric plants in ERCOT as reported to ERCOT by utilities, plus other plants which are in Texas but are reported elsewhere.

The majority of hydroelectric plants in the ERCOT region, whether or not reported by ERCOT operate at relatively low load factor, providing peaking capacity and energy regularly, plus thermal replacement energy when energy is available beyond the peaking requirement. Plants within ERCOT operate intrastate only; the output of Federal plants is marketed interstate by Southwestern Power Administration and the plants are not reported by ERCOT, even though the plants are in the ERCOT region. Other hydropower plants not reported by ERCOT operate to serve nearby loads.

Load Resource Analysis

The ERCOT system operates as one independent interconnected intrastate system. The peak demand occurs in summer, and the margin was 38.1% of the peak demand in 1977. Table IX-7 summarizes the existing capability, peak hour demand, and margin for the past three years.

Table IX-8 gives a load resource balance as projected by ERCOT for 1978. The margin is about 38% of the demand requirements.

For 1978, ERCOT is expected to be a net importer of 130 MW. In addition, ERCOT has an emergency transfer capability of 900 MW between the northern and the southern part of Texas.

Table IX-6

ERCOT
HYDROPOWER CAPABILITY
1977

System	Conventional Hydro Plant Name	Conventional Hydro Capability-MW
Hydroelectric Plants Reported to ERCOT by Utilities		
Lower Colorado River Authority	Austin	14
	Buchanan 1/	36
	Granite Shoals (L.B. Johnson)	52
	Inks	12
	Marble Falls	32
	Marshall Ford (Marshfield)	84
		230
Federal Plants Marketed by Southwestern Power Administration		
Corps of Engineers	San Rayburn	52
	Whitney	30
	Denison	70
		152
Other Plants		
Guadelupe Blanco River Authority	6 small plants	16
International Boundary and Water Commission	Falcon	32
Brazos River Authority	Morris Sheppard	22
Sabine River Authority (Louisiana and Texas)	Toledo Bend	81
Miscellaneous	2 small plants	10
		161
		543

Note: The above are plants reported to ERCOT by utilities. In addition, some small unreported plants are approximately as follows: 9 MW Investor-owned, 61 MW Federal, and 39 MW Publicly-owned (non-federal); Total 109 MW.

1/ The Buchanan plant has a total installed capacity of 22.5 MW of which 11.25 MW is pumped storage.

Reference: [IX-2]

Table IX-7

ERCOT
RESOURCES, DEMAND AND MARGIN
(1975 - 1977)

	1975	1976	1977
Existing Capability-MW	33,010	34,033	37,029
Peak Hour Demand-MW	23,140	25,180	26,820
Margin-MW	9,870	8,853	10,209
Percentage of demand-%	29.9	26.0	27.5
Percentage of capability-%	46.6	35.2	38.1

References: [IX-2, IX-6, and IX-7]

Table IX-8

ERCOT
RESOURCES, DEMAND & MARGIN
Projected for 1978

	Summer	Winter
Resources in MW		
Net Dependable Capability	38,996	38,963
All Scheduled Imports	225	226
All Scheduled Exports	95	96
Total Resources	39,126	39,093
Inoperable Capability	1,124	3,898
Operable Resources	38,002	35,195
Demand in MW		
Peak Hour Demand	28,950	19,894
Interruptible Demand	672	732
Demand Requirements	28,278	19,162
Margin in MW		
Margin	9,724	16,033
Scheduled Outage	40	7,902
Adjusted Margin	9,684	8,131
Percentage of Demand Requirements	34.2%	42.4%
Percentage of Operable Resources	25.5%	23.1%

Reference: [IX-2]

REFERENCES

IX-1 National Electric Reliability Council, 1977 National Report.

IX-2 ERCOT, "Report to the U.S. Department of Energy on Coordinated Bulk Power Supply Programs" FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

IX-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," August 1978.

IX-4 Federal Power Commission, "FPC Form 12," Washington, D.C., 1977.

IX-5 U.S. Water Resources Council, "1972 OBERS projection", Volume 1-2, Washington, D.C., April 1974.

IX-6 ERCOT, "Report to Federal Power Commission," Order No. 383-3, Docket R-362, April 1, 1976.

IX-7 National Electric Reliability Council, 1976 National Report.

Chapter X

WESTERN SYSTEMS COORDINATING COUNCIL

WSCC

Introduction

The Western Systems Coordinating Council (WSCC) was formed in 1967 and is the largest geographically of the nine regional reliability councils which comprise the National Electric Reliability Council (NERC). This chapter presents an overview of the electric power systems in the region. A summary of the regional electric power demand and supply is presented as well as the regional load resource balance.

Regional Power System

Western Systems Coordinating Council, referred to as WSCC was formed in March 1967 to promote bulk power system reliability through coordinated planning and operation. The execution of the WSCC agreement was completed on August 4, 1967 preceeding the formation of the National Electric Reliability Council (NERC) [X-1][1/] WSCC is one of the nine regional reliability councils of power suppliers which make up NERC and serve the United States and parts of Canada (See Eihibit I-1). The WSCC Region includes the States of Arizona, California, Colorado, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming, most of the states of Montana, and New Mexico, and small sections of the states of Nebraska, South Dakota, and Texas. The WSCC region also includes a major portion of the province of British Columbia, Canada.

Delineation of Region

The WSCC area covers approximately 16 million square miles, a little less than 50 percent of the total contiguous land area of the U.S. making it the largest of the nine reliability councils. WSCC consists of five natural sub-regions based on concentrations of resources and economic influences in the geographic location as well as the growth of population and industry. These five natural sub-regions are the Northwest Power Pool Area which includes British Columbia, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, the Southern California - Nevada Power Area, and the Northern California - Nevada Power Area whose

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1/ Number in brackets refer to the list of references at the end of the chapter.

boundaries are shown on Exhibit I-1. In this analysis data will be reported for these five sub-regions as delineated by WSCC excluding the Canadian Systems in the Northwest Power Pool Area.

Within the WSCC, managements of various electric systems have developed a wide variety of formal and informal coordinating organizations and power pools. Formal power pools have been organized to coordinate the planning and/or operation of their facilities to acheive greater economy and reliability. Informal coordinating organizations have developed whose primary concerns are with planning and operation, but unlike the formal power pools the members of the informal groups are not contractually obligated to undertake any specific course of action or provide service to other members. Information on the various regional planning organizations is contained in "Power Planning Organizations in the Pacific Northwest," July 1978, [X-6].

Ownership

WSCC is a voluntary organization open to all bulk power suppliers, and through affiliate membership to all operating power systems in the WSCC service area.

The WSCC member systems, affiliate members and reporting non-members are listed on Exhibit X-2. In addition, there are approximately 332 other systems whose data is reported by the above utilities. According to the WSCC report [X-1], as of January 1978, the WSCC Region now consists of 46 member systems and 13 affiliate members. The member systems include 19 investor - owned utilities, 9 municipal utilities, 12 state chartered authorities (including 4 state cooperatives), 4 Federal agencies and 2 Canadian systems. The affiliate members include 9 municipal utilities, 3 cooperatives and 1 state utility district.

Table X-1 shows only the number of reporting utilities in each category and the respective capability in MW as well as percent of total for the WSCC area and the five sub-regions. Table X-1 reflects those utilities who report their capability in Item-2A of the WSCC report to D.O.E., Order 383-5, Docket R-362 [X-1]. Some members and affiliates report their capability to other members and are not represented in the table. In addition, there are twelve reporting utilities in WSCC who are non-members. Table X-1 shows that WSCC has 54.1% of the summer net generating capability

Table X-1

WSCC
OWNERSHIP OF GENERATION SOURCES[1/]
AS OF JANUARY 1, 1978

WSCC	Investor-Owned	Cooperative	State	Municipal	Federal	Totals
Number of Utilities						
Members	19	4	7	9	3	42[2/]
Affiliates	-	-	-	2	-	2[3/]
Non-Members	1	-	2	9	-	12
Total	20	4	9	20	3	56
Capability						
MW	50,301	1,055	9,274	11,584	20,715	92,929
%	54.1	1.1	10.0	12.5	22.3	100.0
NORTHWEST POWER POOL AREA						
Number of Utilities						
Members	7	-	4	3	4[4/]	18
Affiliates	-	-	-	1	-	1
Non-Members	-	-	-	4	-	4
Total	7	-	4	8	4	23
Capability						
MW	13,420	-	4,390	2,569	16,851	37,230
%	36.0	-	11.8	6.9	45.3	100.0
ROCKY MOUNTAIN POWER AREA						
Number of Utilities						
Members	3	2	1	1	2[4/]	9
Affiliates	-	-	-	1	-	1
Non-Members	-	-	-	-	-	-
Total	3	2	1	2	2	10
Capability						
MW	2,697	842	1	392	2,059	5,991
%	45.0	14.1	0.0	6.5	34.4	100.0
ARIZONA-NEW MEXICO POWER AREA						
Number of Utilities						
Members	4	2	1	-	2	9
Affiliates	-	-	-	-	-	-
Non-Members	1	-	1	2	-	4
Total	5	2	2	2	2	13
Capability						
MW	6,225	213	3,698	339	545	11,020
%	56.5	1.9	33.6	3.1	4.9	100.0
SOUTHERN CALIFORNIA-NEVADA POWER AREA						
Number of Utilities						
Members	3	-	1[5/]	4	-	8
Affiliates	-	-	-	-	-	-
Non-Members	-	-	1	1	-	2
Total	3	-	2	5	-	10
Capability						
MW	15,741	-	145	6,295	-	22,181
%	71.0	-	0.7	28.3	-	100.0
NORTHERN CALIFORNIA-NEVADA POWER AREA						
Number of Utilities						
Members	2	-	1[5/]	1	1	5
Affiliates	-	-	-	-	-	-
Non-Members	-	-	-	2	-	2
Total	2	-	1	3	1	7
Capability						
MW	12,218	-	1,040	1,989	1,260	16,507
%	74.0	-	6.3	12.1	7.6	100.0

1/ Based on Summer Generating Capability.

2/ Total does not include Canadian Systems. The Western Area Power Administration (federal) and the Arizona Power Authority (State) are not counted in the total as they do not report their own capability in Item 2A [X-1]. The divisions of the U.S.B.R. are counted separately in their respective sub-regions but are counted as one in the WSCC total.

3/ Only 2 of a total of 13 affiliate members report their own capability in Item 2A [X-1].

4/ The U.S.B.R. (Upper Colorado Division) reports part of its capability in the Northwest Power Pool Area and the remaining in the Rocky Mountain Power Area.

5/ The Department of Water Resources/California reports part of its capability in the North California Nevada Power Area and the remaining in the South California - Nevada Power Area.

Reference: [X-1]

represented by investor-owned utilities, 1.1% by cooperatives, 10.0% by state, 12.5% by municipal, and 22.3% by federal. These utility systems provide substantially all of the electric service in the WSCC area.

Transmission System

As of January 1, 1978 the WSCC interconnected power system was comprised of a total of 44,337 miles of transmission lines at 230 KV and higher. The existing transmission lines as of January 1, 1978 are shown in Table X-2.

Table X-2

WSCC
TRANSMISSION LINES
As of January 1, 1978

Voltage (KV)	Transmission Line (Circuit Miles)
Alternating Current	
230	28,828
345	5,911
500	8,660
Direct Current	
250	94
400-450	-
800	844

Reference [X-3]

Power Exchange and Interties between Regions

As mentioned earlier WSCC is one of the largest of the nine regional groups of power supplier members of NERC. The benefits of interconnection have long been recognized and expansion of interconnections among systems in the western states and western Canada resulted in the complete interconnection of the region in the mid 1960's. Interconnections to the eastern systems bordering WSCC followed in 1967. The eastern systems adjoining WSCC are the

Mid-Continent Area Reliability Coordination Agreement (MARCA), the Southwest Power Pool (SWPP), and the Electric Reliability Council of Texas (ERCOT), as shown on Exhibit I-1. At present, these interconnections are very weak, however by strengthening these interconnections system flexibility and operation can be increased contributing to a more economical and reliable system operation.

Regional Electric Power Demand

Existing data shows a 4.8% average annual increase in energy demand and a 4.0% annual increase in peak demand over the last ten years. Power generating resources exceed demand requirements.

Socio-Economic Conditions

The WSCC area is divided into five power service sub-regions. The earnings, per capita income and population are shown in Table X-3. The demographic and economic data on WSCC were obtained from BEA economic areas corresponding reasonably close but not exactly with WSCC boundaries. The WSCC region is shown on the map of Exhibit I-2. The BEA areas approximating the sub-regions within WSCC are as follows:

Northwest Power Pool Area	- 94,95,151,152,153,154, 155,156,157,158,159;
Rocky Mountain Power Area	- 147,148,149,150;
Arizona-New Mexico Power Area	- 145,146,162,163;
Southern California-Nevada Power Area	- 161,164,165,166; and
Northern California-Nevada Power Area	- 160,167,168,169,170, 171.

Between 1950 and 1970 the population of WSCC has been increasing at an average annual rate of 2.8%. The WSCC share of national population has been increasing, indicating a population growth rate higher than the national rate. In 1970, the WSCC population was about 17% of the national population. The Southern California - Nevada Power Area contained 39% of the 1970 WSCC population, the largest share of the five sub-regions. Also, the Southern California - Nevada Power Area has exhibited a higher population growth

Table X-3

WSCC
ECONOMIC INDICATORS
1970

	Northwest Power Pool Area	Rocky Mtn. Power Area	Arizona - New Mexico Power Area	S. California-Nevada Power Area	N. California-Nevada Power Area	Entire WSCC Region
Sector Earnings 1/ (Million $)						
Agriculture	1,162	378	373	1,173	734	3,820
Mining	242	223	339	275	73	1,151
Construction	1,277	484	538	2,217	1,374	5,890
Manufacturing	4,468	1,003	990	10,165	4,233	20,859
Transportion Utilities	1,560	543	478	2,504	2,044	7,129
Trade	3,610	1,175	1,192	6,938	3,756	16,671
Finance	949	341	357	2,132	1,265	5,045
Services	2,889	1,000	1,209	7,137	3,708	15,943
Government	4,479	1,599	1,893	7,692	5,734	21,397
Total Earnings (Million $) 1/	20,635	6,747	7,369	40,684	22,933	98,368
Population (Thousands)	8,000	2,533	3,050	13,169	7,354	34,106
Per Capita Income ($) 1/	3,273	3,353	3,011	3,875	4,021	3,649
Per Capita Income Relative to the U.S.	0.942	0.965	0.866	1.115	1.157	1.050

Reference: [X-4]

Note: (1) Due to rounding, the sum of parts may not equal totals. The sum of sector earnings may not equal total earnings since some data for individual REA sector earnings was deleted to avoid disclosure of data pertaining to a particular establishment.

(2) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

rate than the other WSCC sub-regions. The average annual population growth rate in the Southern California - Nevada Power Area was 3.5 percent between 1950 and 1970. The Northwest Power Pool Area and the Northern California - Nevada Power Area respectively contained 23 and 22% of the WSCC population in 1970. The population in the Northwest Power Pool Area has been growing at about the same rate as the United States average of 1.5%, but lower than the WSCC region average. The population of the Northern California - Nevada Power Area has been growing at about the same rate as the WSCC average. The Arizona-New Mexico Power Area included approximately 9% of the total WSCC population in 1970. This area has experienced a population growth of 3.4% between 1950 and 1970. The population growth in the Rocky Mountain Power Area has been about 2.5% between 1950 and 1970. The Rocky Mountain Power Area included only 7% of the 1970 WSCC population.

Table X-3 shows 1970 industrial sector earnings for WSCC and component subregions. The primary source of income in the region has been from the government and manufacturing sectors. The service and trade sectors also are important in terms of earnings. From a national standpoint, the government earnings originating in WSCC represent 22% of the 1970 national government earnings total. Mining and agriculture in the area each made up about 20% of their respective national earnings total. WSCC based manufacturing, although largest in terms of dollar earnings, only produced 13% of the national manufacturing earnings. Over the period from 1950 through 1970, WSCC total earnings have been increasing at an average annual growth rate of about 5%. The 1970 WSCC share of national earnings is about 17%.

The individual power service subregions show distributions of industrial sector earnings similiar to the overall WSCC region. As with population, the Southern California - Nevada Power Area produces the largest percentage of the WSCC earnings. The Northern California - Nevada Power Area and Northwest Power Pool Area each produced approximately 22% of the WSCC earnings in 1970. The Northern California-Nevada Power Area distribution of total earnings is slightly higher in the finance, services and government sectors than the earnings originating in the corresponding sectors within the Northwest Power Pool Area. However, the Northwest Power Pool Area has a higher concentration of earnings in the agriculture and mining sectors, when compared to the Northern California subregions. Trade and government are the major earnings sectors in the Rocky Mountain Power Area and the Arizona-New Mexico Power Area. In addition, the Rocky Mountain and the Arizona-New Mexico Power Areas are important contributors to the mining earnings originating in the WSCC region.

Per capita income in the WSCC region has been growing at an average annual rate of 2.2% from 1950 through 1970. In 1970, the per capita income was 5% higher in the WSCC region than the national average. Table X-3 shows the per capita income for each power service subregion and the index with respect to the 1970 national average. Both the Northern California-Nevada and Southern California-Nevada Power Areas had per capita income higher than the U.S. average. The Arizona-New Mexico Power area region had the lowest per capita income, but experienced the highest growth rate between 1950 and 1970. The Rocky Mountain Power Area region experienced a per capita income growth rate of 2.4 percent from 1950 through 1970, however per capita income is still less than the WSCC regional average. The Northwest Power Pool Area has a low 1970 per capita income and has experienced a growth rate of only 2.1 percent annually.

Peak Demand

Pertinent data for peak demands since 1975 are given in Exhibit X-3 for WSCC and the five subregions. Historically, WSCC is a winter peaking system, however, 1977 was the fifth consecutive year that a summer peak was experienced. Peak demand for WSCC observed during 1977, was 64.9 GW as shown on Table X-4. The annual load factor resulting from this demand is 67.8%. During 1977 WSCC was the only area within NERC to experience a lower peak load than that which occurred in 1976. The highest peak demand within the five subregions of WSCC was 26.6 GW observed in the Northwest Power Pool Area which was the only winter peaking subregion. The Rocky Mountain Power Area had the lowest peak demand of 4.2 GW with a resulting annual load factor of 66.2%. The Arizona-New Mexico Power Area, Southern California-Nevada Power Area and the Northern California-Nevada Power Area had summer peak demands of 7.3, 18.8, and 14.2 GW, respectively.

Energy Demand

The annual energy values from 1975 to 1977 are shown on Exhibit X-3. WSCC has experienced an average annual growth rate of 3.8% from 1975 to 1977. The energy consumption for

WSCC during 1977 was 385,887 GWh as shown on Table X-4. This was approximately 5% below that forecasted for the year because of voluntary customer curtailments, the curtailment of interruptable loads, and mild temperatures experienced during the 1977 drought. The Northwest Power Pool Area consumed about 40% (153,023 GWh) of the total WSCC energy consumption, while the Rocky Mountain Power Area and the Arizona-New Mexico Power Area each consumed under 10%.

Table X-4

WSCC
ANNUAL ENERGY, PEAK
DEMAND AND LOAD FACTOR 1977

	Annual Energy GWh	Peak Demand MW	Month of Peak Demand	Annual Load Factor %
WSCC	385,887	64,926	August	67.8
Northwest Power Pool Area	153,023	26,641	January	65.6
Rocky Mountain Power Area	24,367	4,200	June	66.2
Arizona-New Mexico Power Area	35,787	7,266	August	56.2
So. California-Nevada Power Area	96,666	18,815	September	58.6
No. California-Nevada Power Area	76,044	14,157	July	61.3

Reference [X-1]

Consumer Categories. Energy consumption as percent of total during 1977 for the consumer categories (Residential, Commercial, and Industrial consumers) for representative utilities in each of the five subregions are given in Table X-5. Annual growth rates of electric demand by the consumer categories for the period 1972-1977 are given in Exhibit X-4. Electric demand for all categories increased during the last 6 years except in 1974 as a result of the 1973 oil embargo. In general, the residential and commercial categories have experienced the highest increases in energy consumption with the greatest residential increases occurring in the Northwest Power Pool Area while the highest increases in the commercial category occurred in the Arizona-New Mexico Power Area. Industrial consumption in the five subregions had the slowest growth rates with decreases occurring in 1974 and 1975 at many of the utilities with the exception of the Rocky Mountain Power Area where industrial consumption had the highest growth rates of the three consumer categories.

Load Characteristics

Load Factor. The annual load factor from 1975 to 1977 for WSCC and the five subregions are given in Exhibit X-3. The annual load factor for 1977 in WSCC was 67.8%. The highest load factor in 1977 within the five subregions was 66.2% in the Rocky Mountain Power Area while the lowest of 56.2% was experienced in the Arizona-New Mexico Power Area.

Seasonal Variations. WSCC is historically a winter peaking region, however summer peaks have been experienced for the last five years. The monthly energy, peak demands and load factors for 1977 are shown on Table X-6. Exhibit X-5 shows the peak demand as percent of annual as well as the weekly load factor for the first week in April, August, and December of the five subregions of WSCC. It can be seen from the Exhibit that the utilities representing the Northwest Power Pool Area and the Rocky Mountain Power Area are predominately winter peaking systems while the Arizona-New Mexico Power Area, So. California - Nevada Power Area, and No. California - Nevada Power Area are predominately summer peaking. Weekly load and load duration curves for representative utilities in WSCC are given in Exhibit X-6.

Regional Electric Power Supply

Existing Generating Facilities

Exhibit X-7 shows total capability according to plant types for the five subregions in WSCC, as well as a breakdown of capability for utilities in each of the five subregions. As of January 1, 1978 the existing generation capability of

Table X-5

WSCC
ENERGY CONSUMPTION BY CONSUMER CATEGORIES[1/]
1977

Representative Utilities	Residential	Commercial	Industrial	Total
Northwest Power Pool Area				
Pacific Power & Light Company	38.3	25.6	36.1	100.0
Rocky Mountain Power Area				
Public Service Company of Colorado [2/]	26.0	33.3	40.7	100.0
Arizona-New Mexico Power Area				
Salt River Project	45.9	54.1[3/]		100.0
So. California-Nevada Power Area				
Southern California Edison Company	31.9	30.9	37.2	100.0
No. California-Nevada Power Area				
Pacific Gas & Electric Company[4/]	70.8[5/]		29.2	100.0

1/ Data taken from 1977 Annual Reports of respective utilities.

2/ Data estimated from graphs. Industrial includes other consumers.

3/ Commercial and Industrial are combined.

4/ Values shown are for 1976. Data estimated from graphs.

5/ Commercial and Residential are combined.

Table X-6

WSCC
MONTHLY ENERGY AND PEAK DEMAND
1977

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
WSCC													
Peak Demand, MW	62104	58114	56510	54540	58118	61904	64676	64926	64036	56358	61432	61525	64926
Net Energy, GWh	34679	29476	32774	29825	30324	32181	34371	34659	30978	30974	31723	33923	385887
Load Factor,%	75.1	75.5	78.0	76.0	70.1	72.2	71.4	71.8	67.2	73.9	71.7	74.1	67.8
NORTHWEST POWER POOL AREA													
Peak Demand, MW	26641	24293	22809	21085	20944	20006	20135	20501	20204	21243	26541	25551	26641
Net Energy, GWh	15433	12446	13542	11752	11994	11632	11997	12121	11308	12279	13683	14836	153023
Load Factor,%	77.9	76.2	79.8	77.4	77.0	80.8	80.0	79.5	77.7	77.7	71.6	78.0	65.6
ROCKY MOUNTAIN POWER AREA													
Peak Demand, MW	3918	3599	3538	3496	3571	4200	4518	4196	3950	3626	3935	4062	4518
Net Energy, GWh	2089	1820	2067	1930	1868	2086	2324	2175	1936	1937	2011	2124	24367
Load Factor,%	71.7	75.3	78.5	76.7	70.3	69.0	69.1	69.7	68.1	71.8	71.0	70.3	65.6
ARIZONA-NEW MEXICO POWER AREA													
Peak Demand, MW	4960	4795	4849	5394	6359	7130	7152	7266	7110	5693	4538	4819	7266
Net Energy, GWh	2677	2417	2775	2684	2828	3511	3820	3951	3305	2711	2480	2628	35787
Load Factor,%	72.5	75.0	76.9	69.1	59.8	68.4	71.8	73.1	64.6	64.0	75.9	73.3	56.2
SOUTHERN CALIFORNIA - NEVADA POWER AREA													
Peak Demand, MW	14834	14320	14144	13992	15133	16455	18714	18502	18815	15077	14847	15125	18714
Net Energy, GWh	7986	7157	7993	7504	7655	8162	8977	9189	8188	8071	7701	8083	96666
Load Factor,%	72.4	74.4	76.0	74.5	68.0	68.9	64.5	66.8	60.4	72.0	72.0	71.8	59.0
NORTHERN CALIFORNIA - NEVADA POWER AREA													
Peak Demand, MW	11751	11107	11170	10573	12111	14113	14157	14461	13957	10719	11571	11968	14461
Net Energy, GWh	6494	5636	6397	5955	5979	6790	7253	7223	6241	5976	5848	6252	76044
Load Factor,%	74.3	75.5	77.0	78.2	66.4	66.8	68.9	67.1	62.1	74.9	70.2	70.2	60.0

Reference [X-1]

the total WSCC region was about 93,000 MW. As shown in Table X-7, much of the electric resources is provided by hydroelectric plants (38,816 MW, or 41.8%). This is due primarily to the geography of northern California and the Pacific Northwest States which is most suitable for hydroelectric development. Oil-fired steam units provide the second highest portion of generation capability at 25.7%, with total steam units providing 45.4% (17.4% coal and 2.3% gas). Nuclear, Combustion Turbines, Internal Combustion, Combined Cycle, Pumped Storage, and others provide only a small percentage of the total generation facilities. According to WSCC the principal resource additions during 1977 included one 400-MW coal-fired unit, two 400-MW hydro units, two pumped storage units (having a total capacity of 450 MW) and combined cycle units with a capacity of 860 MW [X-3].

The Northwest Power Pool Area which contains about 40% of the total generation capability of WSCC contributes most of the hydroelectric generation (about 71%) in the WSCC Region while representing 73.6% in the subregion itself. Hydroelectric generation provides much of the capability in the Rocky Mountain Power Area (34.7%) and the Northern California-Nevada Power Area (37.4%) as well. Except for the Northwest Power Pool Area oil and steam-fired units represent the bulk of generation facilities in the other four subregions. Coal-fired steam provides 46.1 and 47.0% of generating capability in the Rocky Mountain Power Area and the Arizona-New Mexico Power Area, respectively, while oil-fired units provide 62.7 and 45.4% of generation capability in the Southern California-Nevada Power Area and the Northern California-Nevada Power Area, respectively.

<u>Current Role of Hydropower</u>

As mentioned in the previous section conventional hydropower represents approximately 42% (38,816 MW) of WSCC's total generation facilities, with an additional 2% from pumped storage facilities. Table X-8 shows the ownership of hydropower facilities for WSCC and the five subregions as of January 1, 1978. Forty-five utilities in WSCC have hydropower capability. Most of the hydro capability (48.6%) is controlled by the federal government, the Department of Interior and the Corps of Engineers, while most of the remaining capability is shared equally by privately-owned and state and local governments (22.8% and 28.5%, respectively). The bulk of the hydropower facilities in WSCC are located in the Northwest Power Pool Area (about 27,390 MW or 71%) while

Table X-7

WSCC
GENERATING CAPABILITY BY TYPE OF PLANTS[1/]
AS OF JANUARY 1, 1978

	WSCC		Northwest Power Pool Area		Rocky Mountain Power Area		Arizona-New Mexico Power Area		Southern California-Nevada Power Area		Northern California-Nevada Power Area	
	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Summer Capability	92,929		37,230		5,991		11,020		22,181		16,507	
Winter Capability	93,082		37,406		6,114		11,018		22,219		16,325	
<u>Generation Mix in Summer</u>												
Nuclear	2,504	2.7	1,130	3.0	0	0.0	0	0.0	436	2.0	938	5.7
Coal-fired steam	16,205	17.4	6,336	17.0	2,769	46.1	5,190	47.0	1,910	8.6	0	0.0
Oil-fired steam	23,912	25.7	226	0.6	124	2.1	2,187	19.8	13,887	62.7	7,488	45.4
Gas-fired steam	2,097	2.3	110	0.3	261	4.4	665	6.0	595	2.7	466	2.8
Combustion Turbine[2/]	3,531	3.8	215	0.6	538	9.0	1,310	11.9	1,190	5.3	278	1.7
Internal Combustion[2/]	530	0.6	378	1.0	55	1.0	15	0.1	30	0.1	52	0.3
Combined Cycle	1,940	2.1	541	1.5	0	0.0	822	7.6	577	2.6	0	0.0
Hydroelectric	38,816	41.8	27,390	73.6	2,082	34.7	691	6.3	2,476	11.2	6,177	37.4
Pumped-Storage	1,893	2.0	0	0.0	162	2.7	140	1.3	985	4.4	606	3.7
Others	1,501	1.6	904	2.4	0	0.0	0	0.0	95	0.4	502	3.0
Total	92,929	100.0	37,230	100.0	5,991	100.0	11,020	100.0	22,181	100.0	16,507	100.0

1/ Generating Capability excludes the Canadian Systems.
2/ Includes both oil and gas fuel types.

Table X-8

WSCC
OWNERSHIP OF HYDROPOWER[1/]
As of January 1, 1978

	Investor-Owned	Cooperative	State	Municipal	Federal	Total
WSCC						
Number of Utilities	12	1	7	15	3[2/]	38
Capability, MW						
Conventional Hydro	9,101	26	5,037	4,841	19,811	38,816
Pumped Storage	162	-	746	985	-	1,893
Total, MW	9,263	26	5,783	5,826	19,811	40,709
%	22.8	0.1	14.2	14.3	48.6	100.0
NORTHWEST POWER POOL AREA						
Number of Utilities	7	-	4	6	4[3/]	21
Capability, MW						
Conventional Hydro	4,569	-	4,390	2,450	15,981	27,390
Pumped Storage	-	-	-	-	-	-
Total, MW	4,569	-	4,390	2,450	15,981	27,390
%	16.7	-	16.1	8.9	58.3	100.0
ROCKY MOUNTAIN POWER AREA						
Number of Utilities	1	1	1	1	2[3/]	6
Capability, MW						
Conventional Hydro	26	26	1	4	2,025	2,082
Pumped Storage	162	-	-	-	-	162
Total, MW	188	26	1	4	2,025	2,244
%	8.4	1.2	0.1	0.1	90.2	100.0
ARIZONA-NEW MEXICO POWER AREA						
Number of Utilities	1	-	1	2	2	4
Capability, MW						
Conventional Hydro	5	-	92	49	545	691
Pumped Storage	-	-	140	-	-	140
Total, MW	5	-	232	49	545	831
%	0.6	-	27.9	5.9	65.6	100.0
SOUTHERN CALIFORNIA-NEVADA POWER AREA						
Number of Utilities	1	-	1[4/]	3	-	5
Capability, MW						
Conventional Hydro	1,132	-	120	1,224	-	2,476
Pumped Storage	-	-	-	985	-	985
Total, MW	1,132	-	120	2,209	-	3,461
%	32.7	-	63.8	3.5	-	100.0
NORTHERN CALIFORNIA-NEVADA POWER AREA						
Number of Utilities	2	-	1[4/]	3	1	7
Capability, MW						
Conventional Hydro	3,369	-	434	1,114	1,260	6,177
Pumped Storage	-	-	606	-	-	606
Total, MW	3,369	-	1,040	1,114	1,260	6,783
%	49.7	-	15.3	16.4	18.6	100.0

Note: The above represent plants reported to the DOE by WSCC. In addition, ownership of small unreported plants (primarily industrial and municipal) in MW are approximately as follows: Industrial 50, Public (non-federal) 176, Federal 9, Private 9, and Cooperative 7.

1/ Based on summer capability.

2/ Each division of the U.S.B.R. has been counted as one utility.

3/ The U.S.B.R. (Upper Colorado Division) reports part of its capability in the Northwest Power Pool Area (10 MW), and the remaining in the Rocky Mountain Power Area (1,462 MW).

4/ The Department of Water Resources/California reports part of its capability in the Southern California - Nevada Power Area (120 MW) and the remaining in the Northern California - Nevada Power Area (434 MW - conventional, 606 MW pumped storage).

Reference: [X-1]

the Northern California-Nevada Power Area provides about 16% (6,783 MW).

The role of conventional hydropower in WSCC is therefore an important one. Interregion transfer of hydro energy from the Pacific Northwest helps displace the expensive oil and coal-fired generation in other areas (i.e. transfers to California in 1976 were equivalent to 40 million barrels of oil). In the Northwest where the proportion of hydroelectric to thermal generation is much higher than in other WSCC subregions, generation is somewhat dependent on the precipitation in the fall and winter months. For instance, because of the drought conditions that prevailed, in 1977 the hydro system could only provide its firm output. The secondary hydro energy normally available for meeting interruptible loads and for displacing high cost thermal generation was not available. Furthermore, because of delays in additions to base load thermal generation, the system was short of energy capability. However, voluntary customer curtailments and the high capacity factor operation of available thermal generating plants, both within and outside the region, helped to compensate for the deficiency.

Table X-9

SOURCES OF ELECTRIC ENERGY GENERATION (Percent)
ACTUAL HYDRO CONDITIONS

Source	1975	1976	1977
Hydro	53	50	35
Coal	17	19	25
Oil	15	17	22
Gas	11	11	12
Nuclear	3	2	5
Geothermal	1	1	1

Reference [X-5]

Load Resource Analysis

The adequacy of power supply and demand as well as reserve margins in the WSCC region is discussed in the following section. The Resources, Peak Demand and Reserve Margin for the total WSCC region and the five subregions comprising WSCC are given in Table X-10.

Table X-10

WSCC
RESOURCES, DEMAND AND MARGIN
Projected for 1978

	WSCC		NWPP[2/]		RMPA		ARZ-NW		SO. CAL-NEV		NO. CAL-NEV	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Resources in MW												
Net Dependable Capability	94,837	98,004	38,014	38,831	6,403	7,021	11,321	11,334	22,467	23,166	16,148	17,510
Scheduled Imports	183	222	273	481	309	354	931	792	3,842	3,694	1,690	746
Scheduled Exports	0	0	3,361	2,160	926	1,015	2,065	2,035	165	258	428	384
Total Resources	95,020	98,226	34,926	37,152	5,786	6,360	10,187	10,091	26,144	26,602	17,410	17,872
Inoperable Capability	403	500	0	0	14	94	8	24	373	373	8	9
Operable Resources	94,617	97,726	34,926	37,152	5,772	6,266	10,179	10,067	25,771	26,299	17,402	17,863
Demand in MW[1/]												
Peak Hour Demand	71,937	69,983	24,674	30,160	5,002	4,606	8,112	5,812	19,904	16,645	15,572	13,056
Interruptible Demand	655	710	518	518	43	43	44	44	25	25	80	80
Demand Requirements	71,282	69,273	24,156	29,642	4,929	4,563	8,068	5,768	19,879	16,620	15,492	12,976
Margin in MW												
Margin	23,335	28,453	10,770	7,510	813	1,703	2,111	4,299	5,892	9,609	1,910	4,887
Scheduled Outage	2,746	4,645	4,446	994	0	140	93	883	349	861	179	949
Adjusted Margin	20,589	23,808	6,324	6,516	813	1,573	2,018	3,413	5,543	8,748	1,731	3,938
Adjusted Margin - (% of Demand Requirement)	28.9	34.4	26.2	22.2	16.4	34.5	25.0	59.2	27.9	52.6	11.2	30.3
Adjusted Margin - (% of Operable Resources)	21.8	24.4	18.1	17.5	14.1	25.1	19.8	33.9	21.5	33.3	9.9	22.0

1/ Demand is peak annual and reflects diversity between summer & winter peaking sub-regions, see Table X-6 for 1977.

2/ Canadian load excluded.

Reference: [X-1]

Table X-11

WSCC
INTERREGION CAPACITY EXCHANGES FOR 1978
SCHEDULED IMPORTS
(All Data in Megawatts)

Sub-region Importing	NWPP	RMPA	ARZ-NM	SO. CAL-NEV	NO. CAL-NEV	Total Imports
NWPP	-	273	0	0	0	273
RMPA	120	-	8	0	0	128
ARZ-NM	137	636	-	158	0	931
SO. CAL-NEV	1,414	0	2,057	-	371	3,842
NO. CAL-NEV	1,690	0	0	0	-	1,690

Table X-12

WSCC
INTERREGION CAPACITY EXCHANGES FOR 1978
SCHEDULED EXPORTS
(All Data in Megawatts)

Sub-region Exporting	NWPP	RMPA	ARZ-NM	SO. CAL-NEV	NO. CAL-NEV	Total Exports
NWPP	-	120	137	1,414	1,690	3,361
RMPA	290	-	636	0	0	926
ARZ-NM	0	8	-	2,057	0	2,065
SO. CAL-NEV	0	0	158	-	7	165
NO. CAL-NEV	0	0	0	428	-	428

Reference [X-1]

Demand-Supply Balance

Table X-10 shows the resources, demand, and reserve margins projected for 1978. Peak demand for WSCC is approximately 71.3 GW while the projected resources are approximately 94.6 GW. The reserve margin is thus 23.3 GW. In general, the system generating facilities appear to be adequate in meeting peak demand with a reasonable reserve margin for each of the five subregions as shown in the table.

Imports and Exports

Net scheduled imports for WSCC during 1978 is 181 MW which amounts to only 0.2%. There are no scheduled exports. The Rocky Mountain Power Area imports the 181 MW (total for WSCC) from MARCA. As seen on Table X-10 the Northwest Power Pool Area, Rocky Mountain Power Area, and Arizona-New Mexico Power Area are net exporters of electric power. The Southern California-Nevada Power Area and Northern California-Nevada Power Area are net importers of electric power. The interregion capacity exchanges within WSCC are shown on Table X-11 and Table X-12. These tables show the scheduled imports and exports which represent capacity transactions into or out of a reporting subregion at the time of an importer's or exporter's peak load that is now (at the time the data is prepared) or is expected to be under contract or agreement for a period specified. Exchanges such as economy, maintenence, general purpose, non-displacement or emergency are not reported in these tables.

Reserve Margins and Regional System Reliability

Electric resources in WSCC for the winter exceed demand requirements by 23,808 MW or 34.4%. Reserve margins for WSCC and the five subregions of WSCC are shown on Table X-10 for both summer and winter. Capacity margins appear to be adequate for 1978. As load continues to grow in WSCC, the capability projected is sufficient for adequate reserve margins, however, potential transmission delays associated with new generation facilities may reduce reserve margins and system reliability.

References

X-1 WSCC, "Reliability and Adequacy of Electric Service," Reply to - United States Department of Energy, Order No. 383-5, Docket R-362, April 1, 1978.

X-2 "The 1970 National Power Survey", FPC, Part I.

X-3 NERC, "8th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems," August 1978.

X-4 U.S. Water Resources Council, "1972, OBERS Projections," Volume 1-2, Washington, D.C., April, 1974.

X-5 WSCC, "Ten Year Coordinated Plan Summary 1978-1987," May 1978.

X-6 "Power Planning Organization in the Pacific Northwest," Power Planning Committee Pacific Northwest River Basins Commission, July 1978.

Chapter XI

ALASKA

Introduction

This chapter presents the current situation of electric power in the state of Alaska. It includes a description of the regional power systems, an analysis of the regional electric power demand and supply, and a load resource analysis. Most of the information in this chapter was only available up to the year 1975. Some information was available for 1977 and is included wherever applicable.

Regional Power System

Delineation of Region

Alaska is separate from the contiguous United States and is not directly tied into the interconnected electric system of the U.S. In this study, it is considered as an independent region. For purposes of discussion in this chapter, the state is divided into six major areas: 1) the Southeast, which includes the capital city, Juneau, 2) the Southcentral which includes the state's largest city, Anchorage, 3) the Yukon (Interior), which includes Fairbanks, 4) the Southwest, 5) the Northwest, and 6) the Arctic. The Northwest and Arctic areas are generally grouped together [XI-1][1/]. Much of the information necessary for this study was not available in terms of these areas where this is the case, the information is summarized as a total for the state.

Ownership

The electric power in Alaska is produced by a large number of systems. Table XI-1 shows the breakdown by number of utilities and distribution by ownership. As shown in this table, most of the state's capacity comes from cooperatively owned systems (34.9%), followed by non-utility sources (32.1%) and municipals (21.3%). A smaller portion of this capacity is contributed by federal (7.0%) and investor-owned utilities (4.7%). In 1975, Alaska's 18 cooperatively owned systems served 63% of the 112,200 retail customers in the state. 63% of the non-utility generating capability are

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1/ Numbers in the brackets represent references shown at the end of the chapter.

Table XI-1

ALASKA
OWNERSHIP OF GENERATION SOURCES
1977

Item	Investor-Owned	Cooperative	Municipal	Federal	Total
Installed Capacity					
MW	51.5	549.1	231.0	76.7	908.3
%	5.7	60.5	25.4	8.4	100.0

Reference: [XI-1]

systems which serve military installations; the remaining 37% is owned by private industry. The 76.7 MW of federally-owned capacity is entirely hydro; this represents 61.1% of the statewide hydro capacity. It is also interesting to note that although there are 27 investor owned utilities in the State, they only represent 4.7% of Alaska's capacity.

Transmission System

As of January 1, 1976, Alaska had 922 miles of installed transmission facilities of 33 kV and above. The majority of these lines deliver power to the Southcentral area of the state which includes the Greater Anchorage area, Palmer, and the Kenai Peninsula. Together, these areas comprise Alaska's largest load concentration. There are 210 miles of lines serving the Yukon, which includes Fairbanks and Healy. 74 miles of transmission lines are located in the Southeast area of the state, where separate power systems serve each community [XI-1]. The length of transmission facilities by voltage level and location in the State is shown in Table XI-2.

Power Exchanges and Interties between Regions

Due to the large distance between load centers within the state and the adverse terrain between them, there were no transmission interties between the major areas as of January 1, 1976. Without connections between main areas, the reliability of power within a system is based on its interconnection with other systems in the area and the coordinating agreements between them. The only significant system interties occur in the Southcentral and Yukon areas. The coordination of area power exchange between systems is seldom formal, usually taking the form of mutual assistance and unstructured interchange agreements [XI-1]. Many systems are entirely isolated internal combustion.

There are studies currently under way to determine the feasibility of an interconnection between the Southcentral and Yukon Areas, which would tie Anchorage and Fairbanks together. Presently, the Alaska District of the U.S. Army Corps of Engineers in conjunction with the Alaska Power Administration is conducting a study on the proposed Upper Susitna hydro project and associated transmission facilities. If these projects are approved, it is likely that the two regions will be connected. The United States Department of

Table XI-2
ALASKA
TRANSMISSION LINES AND MAJOR INTERCONNECTIONS 1/
(January 1, 1976)

Summary

	Voltage Level 2/ kV	Line Length miles		Capacity Rating
Anchorage-Cook Inlet Area	138	121	Overhead	
(and Kodiak)	138	12	Submarine	
	115	215	Overhead	
	69	156	"	
	33	130	"	
	13.8/69	4	"	
Total		638		
Fairbanks Area	138	104	Overhead	
	69	64	"	
	33	42	"	
Total		210		
Southeast Area	138	41	Overhead	
	138	3	Submarine	
	33	30	Overhead	
Total		74		
ALASKA-TOTAL	138	266	Overhead	
	138	15	Submarine	14,000 MW-Mi.
	115	215	Overhead	7,700 MW-Mi.
	69	224	"	2,700 MW-Mi.
	33	202	"	600 MW-mi
Total		922		25,000 MW-Mi.

1/ Lines under 33 kV not included.
2/ Nominal voltage.

Sources: Alaska Public Utilities Commission and Alaska Power Administration.

Reference: [XI-1]

Interior and Canada are now studying the feasibility of interconnections between Alaska, British Columbia, Alberta, and the Pacific Northwest. However, these are at a preliminary stage and require much additional consideration. [XI-1].

Regional Electric Power Demand

Socio-Economic Conditions

Table XI-3 summarizes the significant 1970 demographic and economic data for Alaska. The demographic and economic data are that for BEA economic area 172 as discussed in Chapter I. The map of the region is shown on Exhibit I-2.

The 1970 Alaska poulation was 305,000 and represented about 0.2% of the national total. Over the period 1962 to 1970, the population was growing at an average annual rate of 2.7 percent. The 1975 population was estimated at 365,000, [XI-7] reflecting a higher average annual growth of 3.7 percent for the period 1970 to 1975.

Total earnings in the Alaska area have been growing at an average annual rate of about 4.8 percent. The 1970 Alaska earnings represented about 0.2 percent of the national total. By far, the largest earnings sector has been the government, contributing about 44 percent to the Alaska area total earnings. Construction and trade also contributed a significant portion to the Alaska total earnings.

The 1970 Alaska per capita income of $4,202 is about 21 percent higher than the national average. Between 1962 and 1970, the Alaska per capita income has been growing at the average annual rate of 4.0 percent.

Peak Demand

The non-coincidental peak load for the major Alaskan utilities in 1975 was about 453 MW as shown in Exhibit XI-3. These utilities represent about 75% of the total state-wide demand. The demand increased at an average annual growth rate of 13.5% over the 1965-1975 period, from 127.6 MW in 1965 to 453.2 MW in 1975. Within this period the growth rate from 1970 to 1975 was 14.2%, increasing from 234.4 MW to 453.2 MW [XI-3].

Table XI-3

ALASKA
ECONOMIC INDICATORS
1970

Sector Earnings 1/ (Million $)	
Agriculture	18
Mining	48
Construction	122
Manufacturing	80
Transportation Utilities	111
Trade	135
Finance	31
Services	118
Government	522
Total Earnings (Million $) 1/	1,184
Population (Thousands)	305
Per Capita Income ($) 1/	4,202
Relative to the U.S.	1,209

Notes: (1) The Alaska region corresponds to BEA Area 172.

(2) The sum of earnings does not equal the total because of rounding.

(3) Per capita income is total personal income divided by the population of the area. Total personal income is the sum of earnings (wages, salaries, proprietor's income, and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Reference: [XI-2]

Energy Demand

As shown on Exhibit XI-3, the energy demand for Alaska in 1975, was 1,979 GWh; as in the previous section, the energy demands shown reflect about 75% of the state wide demand. The demand increased at an average annual growth rate of 13.1% over the 1965-1975 period, from 578.5 GWh in 1965 to 1,979 GWh in 1975. The demand in 1970 was 1,044 GWh reflecting an average annual growth rate of 13.7% for the period 1970-1975, as shown in Exhibit XI-4 [XI-3]. An estimate for the 1977 distribution of energy for residential, commercial, and industrial use is shown in Table XI-4.

Table XI-4

ALASKA
ENERGY CONSUMPTION BY
CONSUMER CATEGORIES FOR 1977

	Residential	Commercial 1/	Industrial 2/	Other 3/	Total
GWh	1,113	1,217	56	85	2,471
Percent	45.0	49.3	2.3	3.4	100.0

1/ Small light and power.
2/ Large light and power.
3/ Includes street and highway lighting (14 GWh), other public authorities (63 GWh), railroad and railways (2 GWh) and inter-departmental use (6 GWh).

Reference: [XI-4]

Load Characteristics

Alaska is a winter peaking region. Mean annual temperatures range from 43°F in the southern areas to 10°F in the northern most Arctic areas. Exhibit XI-5 shows the peak demand as percent of the annual peak as well as the weekly load factors for the first week in April, August, and December 1977 of five utilities representing the principal bulk power suppliers in Alaska. These utilities are: the Fairbanks Municipal Utility Systems in the Yukon area, the Chugach Electric Association and Kodiak Electric association in the Southcentral area, the Sitka Electric Department in the Southeast area and the Golden Valley Electric Association. Hourly load and load duration curves for the first week in April, August, and December are shown on Exhibit XI-6.

Regional Electric Power Supply

Existing Generating Facilities

Exhibit XI-7 shows total generating capability according to plant types as well as breakdown of capability for the contributing utilities in the state. As of January 1, 1978, the existing generation capability of Alaska was about 1,088 MW. Of this total 68.4% (744 MW) was represented by utilities and the other 31.6% (344 MW) by the military and industry.

As shown in Table XI-5, most of the electric resources are provided by combustion turbines (516 MW or 56.8%). This predominant use of combustion turbines was due to the availability of low cost natural gas for fuel. In addition, because they operate at favorable altitudes and because of the low Alaskan annual average air inlet temperatures, the capacity and efficiency of combustion turbines is substantially increased. Internal combustion plants provide the second highest portion of generation capability at 21.2% (193 MW); heavy reliance on diesel fueled turbines by most of the rural cooperatives accounts for this portion. Steam turbines and hydro account for 7.5% and 14.5%, respectively, of the total [XI-1]. It should be noted that Alaska has no nuclear generating capability. Although there has been expressed interest in a nuclear generating plant for commercial use, it is considered unlikely that such a power plant would be in operation before the year 2000 due to excessive lead time and competition from hydro and coal energy [XI-5].

Table XI-5

ALASKA GENERATING CAPABILITY BY PLANT TYPE
1977

	Steam Turbine		Combustion Turbine		Conventional Hydro	Internal Combustion		Total
	Gas	Coal	Oil	Gas		Oil	Gas	
MW	14.5	53.5	108.6	407.2	131.5	173.8	19.2	908.3
Percent	1.6	5.9	12.0	44.8	14.5	19.1	2.1	100.0

Current Role of Hydropower

As mentioned in the previous section, conventional hydro-power represents approximately 14.5% (131.5 MW) of Alaska's total generation facilities. Although Alaska has tremendous undeveloped hydroelectric resources, the undeveloped sites either are too large for current loads or are too remote from Alaskan load centers, and development has scarcely begun. There are more than 40 hydroelectric installations presently in Alaska ranging in size from 1.5 to 46,700 kilowatts [XI-1]. Most of the plants are small and of local significance. Those which are large enough to have an impact in supplying power to the state's major load centers are shown in Table XI-6.

These 40 sites are all located in the Southeast and Southcentral areas. The majority of sites, including the largest in the state (46.7 MW Corps of Engineers Snettisham project which serves the load of the city of Juneau) are located in the Southeastern area of the State. The mountainous terrain, heavy annual precipitation (320 inches) and proximity of site locations relative to load centers in this area are reasons which led to its extensive use. Only two major projects are located in the Southcentral area, Cooper Lake (15 MW), owned by the Chugach Cooperative and Eklutna (30 MW), owned by the U.S. Bureau of Reclamation and serving load in the Anchorage area [XI-1, XI-5]. The hydroelectric plants provide capacity and energy that are used to reduce peak thermal demand and overall energy production otherwise supplied by thermal plants. The output of Federal plants is marketed by the Alaska Power Administration.

Table XI-6 also shows the distribution of ownership among the hydro plants. Although the majority are privately owned by municipal utilities or industries, the 2 largest of the 5 major projects built in the last 3 decades are federally owned and operated [XI-1].

Load Resource Analysis

The adequacy of the power supply as well as reserve margins in Alaska are discussed in the following section. The estimated generating capability, peak demand, and reserve margin for the entire Alaska Region as well as the major areas in the State are given in Table XI-7.

Table XI-6

ALASKA
HYDROPOWER CAPACITY AND OWNERSHIP
(January 1976)

System	Plant Name	Capacity kW	Ownership
Southeast Region			
Alaska Elec. Light & Power Co.	Gold Creek	1,600	Private
"	Annex Creek	3,500	Private
"	Upper Salmon Creek	2,800	Private
"	Lower Salmon Creek	2,800	Private
Alaska Power & Telephone Co.	Dewey Lakes	338	Private
Pelican Utility Co.	Pelican Creek	500	Private
Ketchikan Public Utilities			
	Ketchikan Lakes	4,200	Municipal
	Silvis	7,100	"
Metlakatla Power & Light	Purple Lake	3,000	"
Petersburg Municipal Light and Power	Crystal Lake	2,000	"
Sitka Public Utilities	Blue Lake	6,000	"
Alaska Power Administration	Snettisham	46,700	Federal
Southcentral Region			
Chugach Electric Assn., Inc.	Cooper Lake	15,000	Public, Non-Federal
Alaska Power Administration	Eklutna	30,000	Federal
	TOTAL	125,538	

Reference: [XI-1]

Table XI-7

ALASKA ESTIMATED RESOURCES,
DEMAND AND MARGIN 1/
1975

	Generating Capability (MW)	Peak Demand (MW)	Reserve Margin (MW)	(%)
Alaska	738	585	153	20.7
Southeast	139	60	79	56.8
Southcentral	426	396	30	7.0
Yukon	140	112	28	20.0
Southwest, Northwest Arctic Combined	33	17	16	48.5

1/ Utilities only. Military and industrial sources are not considered.

Reference [XI-1]

Demand Supply Balance

The non-conincident winter peak for Alaska utilities was 585 MW in 1975 with 396 MW or 67.7% being contributed by the Southcentral area. The Southeast area accounted for 10.3% (60 MW), the Yukon accounted for 19.1% (112 MW), and the Southwest, Northwest, and Artic areas combined accounted for only 2.9% (17 MW).

Imports and Exports

As previously mentioned, there are no transmission lines between any of the major geographic areas in Alaska. Thus, there is no importing or exporting of power between the different areas. Alaska is also isolated from the Canadian power system, and therefore there is no transfer of power into or out of the Alaska Region.

Reserve Margins and Regional System Reliability

Electric resources in Alaska exceed demand requirements by 153 MW or 20.7%. However, since there is no interconnections, between the major geographical areas in the State, it is more meaningful to consider the reserve margins on an area by area basis. Reserve margins for the major geographical areas ranged from a low of 7.0% in the Southcentral area to a high of 56.8% in the Southeast as shown in Table XI-7.

References

XI-1 *The 1976 Alaska Power Survey*, Volume I, FPC.

XI-2 U.S. Water Resources Council, "1972, OBERS, Projections", Volumes 1-2, Washington, D.C., April 1974.

XI-3 United States Department of the Interior, Alaska Power Administration, "Alaskan Electric Power Statistics, 1960-1975", 1976.

XI-4 Edison Electric Institute, "Edison Electric Statistical Yearbook", New York, New York, 1977.

XI-5 Alaska Division of Energy and Power Development, Department of Commerce and Economic Development, "Alaska Regional Energy Resources," Planning Project-Phase I," Volume I, October 1977.

XI-6 Edison Electric Institute, "Electric Power Statistics for 1977," (DOE/EIa-0034).

XI-7 U.S. Department of Commerce, Bureau of the Census, "Statistical Abstracts, 1978."

Chapter XII

HAWAII

Introduction

This chapter presents the status of electric power demand and supply in the state of Hawaii. An overview of the electric power system is discussed. The electrical generation sources and the regional power demand are identified. A load resource balance is made.

Regional Power System

Delineation of the Region

The State of Hawaii consists of eight principal islands as follows:

	Area, Square miles
Niihau	73
Kauai	553
Oahu	608
Molokai	261
Lanai	140
Kahoolawe	45
Maui	729
Hawaii	4,038

These islands form a 400-mile long arc at the south-eastern end of the archipelago, and comprise more than 99 percent of the region's land area. Of the eight islands, Kahoolawe is barren, uninhabited and under military control; Niihau is privately owned and little developed. The other six islands of Kauai, Oahu, Molokai, Lanai, Maui, and Hawaii, therefore, constitute the principal study region. The study region is shown on Exhibit I-1.

Ownership

Electricity in the State of Hawaii is essentially supplied by utilities and private power producing companies [XII-1][1/]. There are a total of five utility companies servicing the main populated islands. Each of the islands is served by independent power systems. The utility companies are:

1/ Numbers in brackets refer to references listed at end of chapter.

Island	Company
Oahu	Hawaiian Electric Company (HECO)
Hawaii	Hawaii Electric Light Company (HELCO)
Kauai	Kauai Electric Division of Citizens Utilities Company (KED)
Maui-Lanai	Maui Electric Company (MECO)
Molokai	Molokai Electric Company (MOECO)

HECO is the largest company in the State. MECO and HELCO are subsidiaries of HECO. KED is an integral part of Citizens Utilities Companies headquartered in Connecticut. MOECO is the smallest utility company in the State.

Private companies are agricultural processing companies. Electrical generation in the State of Hawaii was first begun in the sugar mills to power the production of sugar and has evolved along with these agriculture based origins.

The electric utilities and agricultural processing companies are listed by their respective island locations in Exhibit XII-2. Table XII-1 summarizes the generating capability by ownership categories in the State of Hawaii for 1976. The generating capability of the investor-owned utilities was about 1,462 MW in 1977.

Power Exchange and Interties between Region

There is no interconnection of power between the islands. However, on individual islands the agricultural processing powerplants maintain various forms of agreements with utility companies for exchange of power (XII-1).

Regional Electric Power Demand

Socio-Economic Conditions

Table XII-2 summarizes the significant 1970 demographic and economic data for Hawaii. The demographic and economic data are that for BEA economic area 173 as discussed in Chapter I. The map of the region is shown in Exhibit I-2.

Table XII-1

HAWAII
OWNERSHIP OF GENERATION SOURCES[1/]
(Based on 1976 Data)

	Total	Percent of Total: Investor-Owned	Percent of Total: Industry
Oahu Island			
Installed Capacity, MW	1,171	97.4	2.6
Energy Generated, GWh	5,168	97.8	2.2
Hawaii Island			
Installed Capacity, MW	159	65.0	35.0
Energy Generated, GWh	469	49.5	50.5
Kauai Island			
Installed Capacity, MW	75	52.9	47.1
Energy Generated, GWh	244	54.5	45.5
Maui and Lanai Islands			
Installed Capacity, MW	116	56.1	43.9
Energy Generated, GWh,	514	60.9	39.1
Molokai Island			
Installed Capacity, MW	8	100.0	-
Energy Generated, GWh	20	100.0	-
State of Hawaii			
Installed Capacity, MW	1,529	88.7	11.3
Energy Generated, GWh	6,415	89.6	10.4

1/ The 1976 data were used.

Reference: [XII-1]

Table XII-2

HAWAII
ECONCMIC INDICATORS
1970

Sector Earnings[1/] (Million $)	
Agriculture	2/
Mining	2/
Construction	279
Manufacturing	177
Transportation Utilities	213
Trade	385
Finance	141
Services	400
Government	873
Total Earnings (Million $)[1/]	2,568
Population (Thousands)	762
Per Capita Income ($)[1/]	4,044
Relative to the U.S.	1,164

Notes: (1) Hawaii region is represented by BEA Area 173

(2) Per capita income is total personal income divided by the population of the area. Total income is the sum of earnings (wages, salaries, proprietor's income and other labor income), property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.
2/ Deleted to avoid disclosure of data pertaining to an individual establishment.
Reference: [XII-2]

The 1970 Hawaii population was 762,000 and represented about 0.4 percent of the national population. Over the period 1962 to 1970, the population has grown at the average annual rate of 1.9 percent. The 1975 population is estimated to be 865,000. The above population figures include military personnel stationed in Hawaii.

Total earnings in the Hawaii region have been growing at the average rate of about 7 percent, between 1962 and 1970. The 1970 Hawaii earnings represented about 0.4 percent of the national total. The largest earnings sectors in Hawaii were government and services, respectively contributing 35 and 16 percent to the Hawaii total earnings. Construction, transportation, and trade sectors are also important in the Hawaii economy.

The 1970 Hawaii per capita income of $4,044 is about 16 percent higher than the national average. During the pericd from 1962 to 1970, the per capita income has been growinq at the average annual rate of 4.6 percent.

Peak Demand

The non-coincident peak demand in the State of Hawaii for 1977 was 1,090 MW in December. Table XII-3 shows the annual energy peak demand and load factor for representative utilities in the State of Hawaii. The Hawaiian Electric Company (HECO) with its subsidiaries, Hawaii Electric Light Company and Maui Electric Company, had a peak demand of about 97% of the total peak demand in the State of Hawaii. Exhibit XII-3 gives the historical annual energy, peak load, and load factor for HECO including its subsidiaries. Also included in Exhibit XII-3 are annual growth rates and average compound annual growth rates for 5-year periods of annual energy and peak load. Data for other utilities are not available for this study, however they represent a small percentage of Hawaii's total capability.

The peak load in HECO increased at an average annual growth rate of about 5.2% over the 1970-1975 period (from 765 MW in 1970 to 985 MW in 1975). During 1975-1976 the annual growth rate was 6.0% and for 1976-1977 it was only 2.8%.

Energy Demand

The net energy in the State of Hawaii for 1977 was 6,160 GWh. The total net energy by HECO was about 95% of the total net energy in the State of Hawaii. As can be seen from Exhibit XII-3 the annual demand for electric energy in HECC increased from about 3,870 GWh in 1970 to 5,309 GWh in

1975. This corresponds to an average annual growth rate of about 6.5%. The demand continued to rise at an annual rate of 6.1% in the 1975-1976 period. However, the rate of growth dropped to 3.9% during the 1976-1977 period.

Annual growth rates of energy consumption by consumer categories for HECO are given in Exhibit XII-4 for the years 1970 through 1977 [XII-3].

Table XII-3
HAWAII

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Island	Representative Utilities	Annual Net Energy GWh	Peak Hour Demand MW	Month of Peak	Annual Load Factor %
Oahu	Hawaiian Electric Company	5,210	905	December	69.2
Hawaii	Hawaii Electric Light Company	422	81	November	59.8
Maui-Lanai	Maui Electric Company	378	72	December	59.6
Kauai	Citizens Utilties Company Kauai Electric Division	183	34	November	62.0

Load Characteristics

The annual load factor in the State of Hawaii for 1977 was 64.5%. The annual load factor for different systems are shown in Table XII-3. It ranges from 59% to 70%.

Exhibit XII-5 shows the weekly load factors for the first week of April, August, and December 1977 for representative utilities in the State of Hawaii. The magnitude of the weekly peak load demand and the date of its occurrence are also given [XII-4]. The utilities in the State of Hawaii have their peak load in either November or December.

Exhibit XII-6 shows weekly load and load duration curves for the Hawaiian Electric Company for the first week of April, August, and December 1977.

Table XII-4 gives the monthly energy, peak demand and load factor during the 12 months of 1977 for the State of Hawaii.

Table XII-4

HAWAII
MONTHLY ENERGY, PEAK DEMAND, AND LOAD FACTOR
1977

Month	Net Energy GWh	Peak Hour Demand MW	Monthly Load Factor %
January	520	1,048	66.7
February	474	1,021	69.1
March	516	1,011	68.6
April	479	969	68.6
May	509	980	69.8
June	502	966	72.2
July	525	984	71.7
August	532	992	72.1
September	524	1,040	70.0
October	538	1,066	67.8
November	515	1,075	66.5
December	526	1,090	64.9
1977	6,160	1,090	64.5

Reference: [XII-5]

Regional Electric Power Supply

Existing Generating Facilities

Oil-fired steam turbine, gas turbine, internal combustion, and hydropower generators are utilized to produce electricity in the State of Hawaii. On agricultural plantations, bagasse derived from processed sugar cane is burned to fuel steam driven generators. Oil-fired steam turbines furnish 83 percent of the States electric capability. Combustion turbines supply much of the remainder. Exhibit VII-7 shows the generating capability of representative utilities by types of plants, this data is summarized in Table XII-5.

Table XII -5

HAWAII 1/
GENERATING CAPABILITY BY TYPE OF PLANTS
As of January 1, 1978

	MW	%
Steam Turbine		
Gas	-	-
Coal	1,212.9	82.9
Oil	-	-
Combined Cycle	-	-
Hydroelectric	3.4	0.2
Combustion Turbine		
Gas	50.5	3.5
Oil	105.4	7.2
Internal Combustion 2/		
Oil	90.0	6.2
TOTAL	1,462.2	100.0

1/ Includes HECO, HELCO, KED, and MECO.
2/ Includes diesel generators.

Reference: [XII-4]

Current Role of Hydropower

Hydroelectric plants provide less than 1 percent of the State's electric utility capability. Total hydroelectric capability for the state is 19.3 MW, most of which is composed of plants which supply less than 1 MW to individual sugar companies. Table XII-6 gives the hydropower capability by companies. Hawaii Electric Light Company operates two hydroelectric power plants, one is 2.25 MW and the other is 1.10 MW, on the island of Hawaii. Hawaiian Commercial and Sugar Company owns two hydropower plants on Maui island, one is 5.80 MW and one is only 0.80 MW. McBryde Sugar Company operates two hydropower plants on the island of Kauai, one is 3.6 MW and one is 1.0 MW. Table XII-7 gives the capability by ownership type.

Hawaii's electric system is vulnerable to fuel oil shortages. Nuclear plants are currently too large to economically serve the present system. Hydropower and generators fueled by bagasses now supply only a small fraction of demand for electricity.

Load Resource Analysis

Table XII-8 presents a load resource balance estimated for the State of Hawaii for the year 1978. With a generating capability of 1,512 MW as of January 1, 1978 and an increase of 6% in peak demand over the 1977 peak load of 1,090 MW, the generating reserve margin would be about 30% of the peak demand.

Table XII-6

HAWAII
HYDROPOWER CAPABILITY
As of January 1, 1978
MW

Island		Conventional
Hawaii	Hawaii Electric Light Company	3.35
	Hilo Coast Processing Company	0.15
	Honokaa Sugar	0.80
	Sub-Total	4.30
Maui	Hawaiian Commercial and Sugar Company	6.60
	Pioneer Mill	0.50
	Sub-Total	7.10
Kauai	McBryde Sugar	4.60
	Kekaha Sugar	1.50
	Lihue Plantation	1.30
	Olokele Sugar	0.50
	Sub-Total	7.90
	Total	19.30

Reference: [XII-1]

Table XII-7

HAWAII
OWNERSHIP OF HYDROPOWER
As of January 1, 1978

	Investor-Owned	Industrial	Cooperative	Total
Hawaii-Island				
Number of Companies	1	1	1	3
Capability, MW	3.35	0.80	0.15	4.30
%	77.9	18.6	3.5	100.0
Maui Island				
Number of Companies	-	2	-	2
Capability, MW	-	7.10	-	7.10
%	-	100.0	-	100.0
Kauai Island				
Number of Companies	-	4	-	4
Capability, MW	-	7.90	-	7.90
%	-	100.0	-	100.0
State of Hawaii				
Number of Companies	1	7	1	9
Capability, MW	3.35	15.80	0.15	19.30
%	17.3	81.9	0.8	100.0

Reference: [XII-1]

Table XII-8

HAWAII
RESOURCES, DEMAND AND MARGIN, MW
Projected for 1978

	Summer	Winter
Generating Capability 1/	1,521	1,521
Peak Demand	1,043	1,155
Margin	478	366
Percent of peak demand	45.8	31.7

1/ Includes HECO, HELCO, KED and MECO.

Source: Computed on basis of data provided by the utilities listed.

<u>References</u>

XII-1 U.S. Army Engineer District, "Hydroelectric Power, Plan of Study, Harbors and Rivers in Hawaii", Honolulu, Hawaii, September, 1977.

XII-2 U.S. Department of Commerce, Bureau of Economic Analysis," 1972 OBERS Projections, Regional Economic Activity in the U.S., Series E Population, U.S. G.P.O., Washington, D.C., April 14, 1974.

XII-3 Hawaiian Electric Company, Inc., "Annual Reports", Honolulu, Hawaii, 1974-1977.

XII-4 U.S. Department of Energy, "FERC (FPC) Form No. 12", 1977.

XII-5 Data based on Monthly Energy Data Reports published by EIA Electric Power Statistics for 1977 (DOE/EIA-0034).

XII-6 Department of Energy, "Principal Electric Facilities," DOE/EIA-0057/1-11, 1978.

GLOSSARY OF TERMS

The following Glossary was developed from the "Glossary of Electric Utility Terms," prepared by the Statistical Committee of The Edison Electric Institute[1/]. The definitions of terms are not intended as rigid legalistic interpretations, but are regarded as generally descriptive of predominant and objective practice.

ADVERSE HYDRO (ADVERSE WATER CONDITIONS) - Water conditions limiting the production of hydroelectric power either from low or restricted water supply or reduced gross head.

ANNUAL PEAK LOAD - See DEMAND, ANNUAL MAXIMUM

AVERAGE HYDRO (AVERAGE WATER CONDITIONS) - Precipitation and runoff conditions which provide water for hydroelectric power generation approximating the most often recurring (mean) amount and distribution over a long time period, usually the period of record, but not more than 50 years.

BASE LOAD - The minimum load over a given period of time.

BASE LOAD STATION - A generating station which is normally operated to take all or part of the base load of the system and operates essentially at constant output.

CAPABILITY - The maximum load a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

> GROSS SYSTEM - The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts.
>
> MARGIN OF RESERVE - See CAPABILITY MARGIN.

1/ Statistical Committee, Edison Electric Institute, "Glossary of Electric Utility Terms," No. 70-40.

NET GENERATING STATION - The capability of a generating station as demonstrated by test or as determined by actual operating experience, less power generated and used for auxiliaries and other station uses. Capability may vary with the character of the load, time of year (due to circulating water temperatures in thermal stations or availability of water in hydro stations), and other characteristic causes. Capability is sometimes referred to as "Effective Rating."

NET SYSTEM - The net generating station capability of a system at a stated period of time (usually at the time of the system's maximum load), plus capability available at such time from other sources through firm power contracts less firm power obligations at such time to other companies or systems.

CAPABILITY MARGIN - The difference between net system capability and system maximum load requirements (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of system maximum (peak) loads without allowance for time diversity between the loads of the several systems. However, within a region, account is taken of diversity between peak loads of systems that are operated as a closely coordinated group.

CAPACITY - The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer. See also NAME PLATE RATING.

DEPENDABLE - The load-carrying ability for the time interval and period specified when related to the characteristics of the load to be supplied. Dependable-capacity of a station is determined by such factors as capability, operating power factor and portion of the load the station is to supply.

HYDRAULIC - The rating of a hydroelectric generating unit or the sum of such ratings for all units in a station or stations.

INSTALLED GENERATING - See NAME PLATE RATING.

PEAKING - Generating units of stations available to assist in meeting the portion of peak load above base load.

PURCHASE - The amount of power available for purchase from a source outside the system to supply energy or capacity.

RESERVE - Thermal generating units available for service.

SPINNING RESERVE - Generating units connected to the bus and ready to take load.

THERMAL - The rating of a thermal electric generating unit or the sum of such ratings for all units in a station or stations.

CAPACITY FACTOR - The ratio of the average load on a machine or equipment for the period of time considered to the capacity rating of the machine or equipment.

CIRCUIT MILES OF ELECTRIC LINE - The total length in miles of separate circuits (not including customer's services), whether 1, 2, 3, 4 or more conductors per circuit.

COMMERCIAL AND INDUSTRIAL - A customer, sales, and revenue classification covering energy supplied for commercial and industrial purposes, except that supplied under special contracts or agreements or service classifications applicable only to municipalities or divisions or agencies of Federal or state governments or to railroads and railways. Usually subdivided into Commercial and Industrial or into Small Light and Power and Large Light and Power. Most companies classify such customers as Commercial or Industrial using the Standard Industrial Classification or predominant kWh use as yardsticks; others still classify as Industrial all customers whose demands or annual use exceeds some specified limit. These limits are generally based on a utility's rate schedules.

CONVENTIONAL FUELS - The fossil fuels of coal, gas, and oil.

COOPERATIVES (COOPERATIVELY-OWNED ELECTRIC UTILITIES) - A group of persons who have organized a joint venture for the purpose of supplying electric energy to a specified area. Such ventures are generally exempt from federal income tax laws. Most cooperatives have been financed by the Rural Electrification Administration.

COORDINATION - The practice by which two or more interconnected power systems augment the reliability of bulk electric power supply by establishing planning and operating standards; by exchanging pertinent information regarding additions, retirements, and modifications to the bulk electric power supply system; and by joint review of these changes assure that they meet the predetermined standards.

CUSTOMER (ELECTRIC) - A customer is an individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated.

DEMAND - The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment expressed in kilowatts, kilovoltamperes or other suitable unit at a given instant or averaged over any designated period of time. The primary source of "Demand" is the power consuming equipment of the consumers. See LOAD.

> ANNUAL MAXIMUM - The greatest of all demands of the load under consideration which occurred during a prescribed demand interval in a calendar year.
>
> COINCIDENT - The sum of two or more demands which occur in the same demand interval.
>
> INSTANTANEOUS PEAK - The maximum demand at the instant of greatest load, usually determined from the readings of indicating or graphic meters.
>
> MAXIMUM - The greatest of all demands of the load under consideration which has occurred during a specified period of time.

NON-COINCIDENT - The sum of two or more individual demands which do not occur in the same demand interval. Meaningful only when considering demands within a limited period of time, such as day, week, month, a heating or cooling season, and usually for not more than one year.

DEMAND INTERVAL The period of time during which the electric energy flow is averaged in determining demand, such as 60 minute, 30 minute, 15 minute or instantaneous.

ELECTRIC UTILITY INDUSTRY OR ELECTRIC UTILITIES - All enterprises engaged in the production - and/or distribution of electricity for use by the public, including investor-owned utility companies; cooperatively owned electric utilities; government owned electric utilities (municipal systems, federal agencies, state projects, and public power districts); and, where the data are not separable, those industrial plants contributing to the public supply.

ELECTRIC UTILITY PLANT - See UTILITY PLANT.

ENERGY, ELECTRIC - As commonly used in the electric utility industry, electric energy means kilowatt-hours.

INTERCHANGE - Kilowatt-hours delivered to or received by an electric utility system from another. They may be returned in kind at a later time or may be accumulated as energy balances until the end of a stated period. Settlement may be by payment or on a pooling basis.

OFF PEAK - Energy supplied during periods of relatively low system demands as specified by the supplier.

ON PEAK - Energy supplied during periods of relatively high system demands as specified by the supplier.

SURPLUS - Energy generated that is beyond the immediate needs of the producing system. This energy is frequently obtained from spinning reserve and sold on an interruptible basis.

EXPORTS, NET (ELECTRIC) - Exports of electrical energy in excess of imports across a political boundary or boundaries, being "Gross Out" less "Gross In" during a stated period. This term is applied also to power flow or load at stated times.

FIRM POWER - See POWER, FIRM.

GAS - A fuel burned under boilers, by internal combustion engines, and gas turbines for electric generation. Includes natural, manufactured, mixed, and waste gas.

GENERATING CAPABILITY - See CAPABILITY, NET GENERATING STATION.

GENERATING STATION (GENERATING PLANT or POWER PLANT) - A station at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy.

> GAS TURBINE - An electric generating station in which the prime mover is a gas turbine engine.
>
> GEOTHERMAL - An electric generating station in which the prime mover is a steam turbine. The steam is generated in the earth by heat from the earth's magma.
>
> HYDROELECTRIC - An electric generating station in which the prime mover is a water wheel. The water wheel is driven by falling water.
>
> INTERNAL COMBUSTION - An electric generating station in which the prime mover is an internal combustion engine.
>
> NUCLEAR - An electric generating station in which the prime mover is a steam turbine. The steam is generated in a reactor by heat from the fissioning of nuclear fuel.
>
> STEAM (CONVENTIONAL) - An electric generating station in which the prime mover is a steam turbine. The steam is generated in a boiler by heat from burning fossil fuels.

GENERATING UNIT - An electric generator together with its prime mover.

GENERATION, ELECTRIC - This term refers to the act or process of transforming other forms of energy into electric energy, or to the amount of energy so produced, expressed in kilowatts.

GROSS - The total amount of electric energy produced by the generating units in a generating station or stations.

NET GROSS - Generation less kilowatt-hours consumed out of gross generation for station use.

GENERATION, NON-UTILITY - Generation by producers having generating plants for the purpose of supplying electric power required in the conduct of their industrial and commercial operations. Generation by mining, manufacturing, and commercial establishments and by stationary plants of railroads and railways for active power is included.

GENERATING RESERVE MARGIN - See CAPACITY, RESERVE.

GENERATOR, ELECTRIC - A machine which transforms mechanical energy into electric energy.

GENERATOR, STEAM - The equipment which uses a heat source to change water into steam.

GOVERNMENT (GOVERNMENT-OWNED ELECTRIC UTILITIES AND AGENCIES - When used in statistical tables to indicate class of ownership, it includes municipally-owned electric systems and federal and state public power projects. Cooperatives are not included in this grouping.

GROSS GENERATION - See GENERATION, ELECTRIC (GROSS).

HYDRAULIC CAPACITY - See CAPACITY, HYDRAULIC.

HYDRO - A term used to identify a type of generating station or power or energy output in which the prime mover is driven by water power.

IMPORTS, NET (ELECTRIC) - Imports of electric energy in excess of exports across a political boundary or boundaries, being "Gross In", less "Gross Out" during a stated period. This term applies also to power flow or load at stated times.

INDUSTRIAL GENERATING STATIONS - Electric generating stations operated by industrial establishments to supply all or part of their own power requirements.

INSTALLED GENERATING CAPACITY - See NAME PLATE RATING.

INSTANTANEOUS PEAK DEMAND - See DEMAND, INSTANTANEOUS PEAK.

INTERNAL COMBUSTION ENGINE - A prime mover in which energy released from rapid burning of a fuel-air is converted into mechanical energy. Diesel, gasoline, and gas engines are the principal types in this category.

INTERRUPTIBLE POWER - See POWER (ELECTRIC), INTERRUPTIBLE.

INTERVAL, DEMAND - See DEMAND, INTERVAL.

INVESTOR-OWNED ELECTRIC UTILITIES - Those electric utilities organized as tax-paying businesses usually financed by the sale of securities in the free market, and whose properties are managed by representatives regularly elected by their shareholders. Investor-owned electric utilities, which may be owned by an individual proprietor or a small group of people, are usually corporations owned by the general public.

INDUSTRIAL - See COMMERCIAL AND INDUSTRIAL.

KILOVOLT (kV) - 1,000 Volts (defined herein).

KILOWATT (kW) - 1,000 Watts (defined herein).

KILOWATT HOUR (kWh) - The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.

KILOWATT HOURS PER CAPITA - Net generation in the United States divided by national population, or the corresponding ratio for any other area.

LOAD - The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power consuming equipment of the customers. See DEMAND.

BASE - See BASE LOAD.

CONNECTED - Connected Load is the sum of the capacities or ratings of the electric power consuming apparatus connected to a supplying system, or any part of the system under consideration.

PEAK - See DEMAND, MAXIMUM and also DEMAND, INSTANTANEOUS PEAK.

LOAD CENTER - A point at which the load of a given area is assumed to be concentrated.

LOAD CURVE - A curve showing power (kilowatts) supplied, plotted against time of occurrence, and illustrating the varying magnitude of the load during the period covered.

LOAD FACTOR - The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, also may be derived by multiplying the energy in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

LOSS (LOSSES) - The general term applied to energy (kilowatt hours) and power (kilowatts) lost in the operation of an electric system. Losses occur principally as energy transformations from kilowatt hours to waste heat in electrical conductors and apparatus.

AVERAGE - The total difference in energy input and output or power input and output (due to losses) averaged over a time interval and expressed either in physical quantities or as a percentage of total input.

ENERGY - The kilowatt hours lost in the operation of an electric system.

LINE - Kilowatt hours and kilowatts lost in transmission and distribution lines under specified conditions.

PEAK PERCENT - The difference between the power input and output, as a result of losses due to the transfer of power between two or more points on a system at the time of maximum load, divided by the power input.

SYSTEM - The difference between the system net energy or power input and output, resulting from characteristic losses and unaccounted for between the sources of supply and the metering points of delivery or a system.

MARGIN OF RESERVE CAPACITY - See RESERVE MARGIN.

MAXIMUM DEMAND - See DEMAND, MAXIMUM.

MEGAWATT (MW) - 1,000 kilowatts.

MUNICIPALLY-OWNED ELECTRIC SYSTEM - An electric utility system owned and/or operated by a municipality engaged in serving residential, commercial, and/or industrial customers, usually, but not always, within the boundaries of the municipality.

NAME PLATE RATING - The full-load continuous rating of a generator, prime mover or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a name plate attached to the individual machine or device. The name plate rating of a steam turbine electric generator set is the guaranteed continuous output in kilowatts or kVA and power factor at generator terminals when the turbine is clear and operating under specified throttle steam pressure and temperature, specified reheat temperature, specified exhaust pressure and with full extraction from all extraction openings.

NETWORK - A system of transmission or distribution lines so cross-connected and operated as to permit multiple power supply to any principal point on it.

NON-COINCIDENT DEMAND - See DEMAND, NON-COINCIDENT.

NUCLEAR ENERGY - Energy produced in the form of heat during the fission process in a nuclear reactor. When released in sufficient and controlled quantity, this heat energy may be used to produce steam to drive a turbine-generator and thus be converted to electrical energy.

NUCLEAR POWER - Power released in exothermic (a reaction which gives off heat) nuclear reaction which can be converted to electric power by means of heat transformation equipment and a turbine generator unit.

NUCLEAR POWERED GENERATING CAPACITY - The rated electrical output of a turbine-generator utilizing a nuclear reactor as the heat-energy source for producing the steam which drives the turbine.

OFF-PEAK ENERGY - See ENERGY, ELECTRIC - OFF-PEAK.

OIL BURNED FOR FUEL - Oil burned for fuel includes fuel oil, crude oil, diesel oil, and small amounts of tar and gasoline, with fuel oil predominating.

PEAK - See DEMAND, MAXIMUM.

PEAK CAPACITY - See CAPABILITY.

PEAK LOAD - See DEMAND, MAXIMUM.

PEAK LOAD STATION - A generating station normally operated to provide power during maximum load periods.

PEAKING CAPACITY - See CAPACITY, PEAKING.

PLANT FACTOR - See CAPACITY FACTOR.

POOL, POWER - See POWER POOL.

POWER (ELECTRIC) - The time rate of generating, transferring or using electric energy, usually expressed in kilowatts.

FIRM - Power or power-producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions.

INTERRUPTIBLE - Power made available under agreements which permit curtailment or cessation of delivery by the supplier.

NON-FIRM - Power or power-producing capacity supplied or available under an arrangement which does not have the guaranteed continuous availability feature of firm power.

OFF-PEAK - See ENERGY, ELECTRIC - OFF-PEAK.

ON-PEAK - See ENERGY, ELECTRIC - ON-PEAK.

POWER PLANT - See GENERATING STATION (GENERATING PLANT OR POWER PLANT).

POWER POOL - A power pool is two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements and maintenance program.

PRIMARY ENERGY - Energy available from firm power. See POWER (ELECTRIC), FIRM.

PRIME MOVER - The engine, turbine, water wheel, or similar machine which drives an electric generator.

PUBLICLY-OWNED ELECTRIC UTILITIES - See GOVERNMENT.

PUBLIC UTILITY DISTRICT - A political subdivision (quasipublic corporation of a state), with territorial boundaries embracing an area wider than a single municipality (incorporated as well as unincorporated) and frequently covering more than one county for the purpose of generating, transmitting, and distributing electric energy.

PUMPED STORAGE - An arrangement whereby additional electric power may be generated during peak load periods by hydraulic means using water pumped into a storage reservoir during off peak periods.

RATING, GENERATOR - See NAME PLATE RATING and CAPABILITY.

RESERVE CAPACITY - See CAPACITY, RESERVE.

RESERVE MARGIN - The difference between net system capability and system maximum load requirements (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of the system maximum (peak) loads without allowance for time diversity between the loads of the several systems. However, within a region, account is taken of diversity between peak loads of systems that are operated as a closely co-ordinated group.

RESIDENTIAL - A customer, sales, and revenue classification covering electric energy supplied for residential (household) purposes. The classification of an individual customer's account where the use is both residential and commercial is based on principal use.

RUN OF RIVER PLANT - A hydroelectric power plant using the flow of the stream as it occurs and having little or no reservoir capacity for storage of water. Sometimes called "Stream-Flow" plants.

SECONDARY ENERGY - A term generally applied to energy available from Non-Firm Power. See POWER (ELECTRIC), NON-FIRM.

SERVICE AREA - Territory in which a utility system is required or has the right to supply electric service to ultimate customers.

SPINNING RESERVE - See CAPACITY, RESERVE - SPINNING.

STANDBY SERVICE - Service that is not normally used but which is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

SUMMER PEAK - The greatest load on an electric system during any prescribed demand interval in the summer (or cooling) season, usually between June 1 and September 30.

SYSTEM, ELECTRIC - The physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control, management, or operating supervision.

SYSTEM INTERCONNECTION - A connection between two electric systems permitting the transfers of electric energy in either direction.

THERMAL - A term used to identify a type of electric generating station, capacity, or capability, or output in which the source of energy for the prime mover is heat.

THERMAL CAPACITY - See CAPACITY, THERMAL.

TRANSMISSION - The act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems. Also a functional classification relating to that portion of utility plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of transmission plant.

TURBINE-GENERATOR - A rotary-type unit consisting of a turbine and an electric generator.

TURBINE (HYDRAULIC) - An enclosed rotary type of prime mover in which mechanical energy is produced by the force of water directed against blades fastened to a horizontal or vertical shaft.

TURBINE (STEAM OR GAS) - An enclosed rotary type of prime mover in which heat energy is steam or gas is converted into mechanical energy by the force of a high velocity flow of steam or gasses directed against successive rows of radial blades fastened to a central shaft.

UTILITY GENERATION - Electric generation by electric systems.

WINTER PEAK - The greatest load on an electric system during any prescribed demand interval in the winter or heating season, usually between December 1 of a calendar year and March 31 of the next calendar year.

LIST OF EXHIBITS

LIST OF EXHIBITS (Cont'd)

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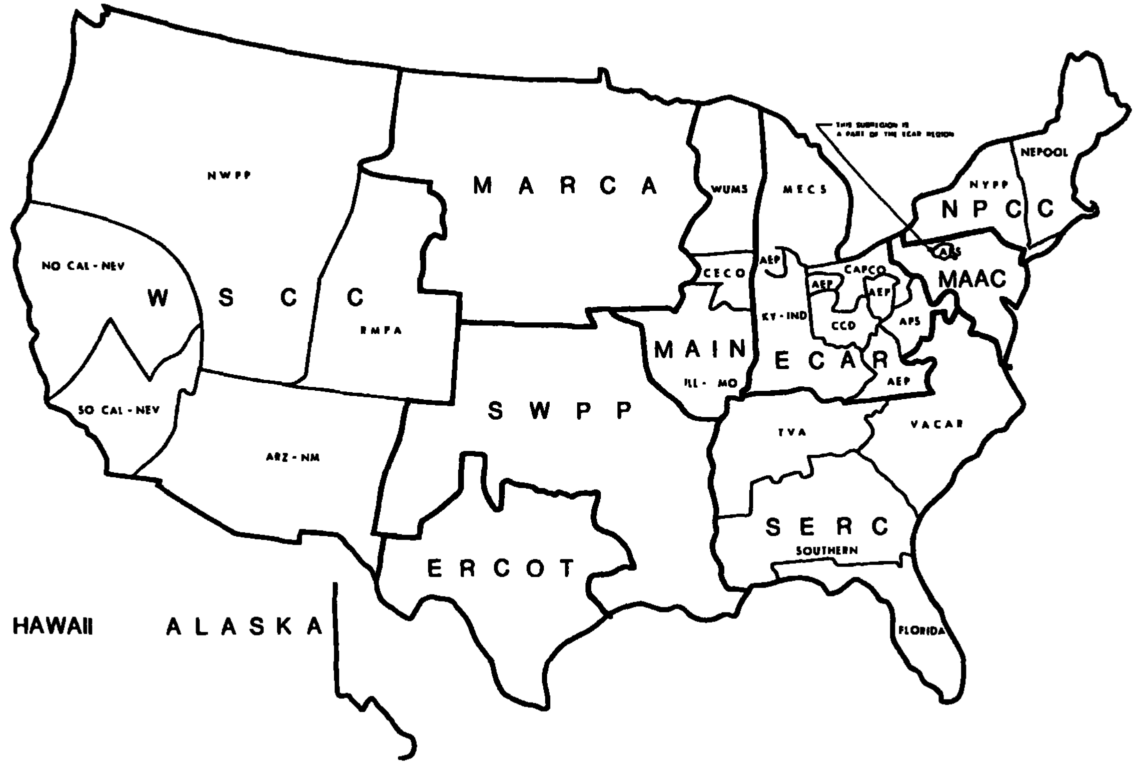
LIST OF EXHIBITS (Cont'd)



ECAR EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT
- APS — ALLEGHENY POWER SYSTEM
- AEP — AMERICAN ELECTRIC POWER
- CAPCO — CENTRAL AREA POWER COORDINATION GROUP
- CCD — CINCINNATI COLUMBUS DAYTON GROUP
- MECS — MICHIGAN ELECTRIC COORDINATED SYSTEM
- KY IND — KENTUCKY INDIANA

MAIN MID AMERICA INTERPOOL NETWORK
- CECO — COMMONWEALTH EDISON
- WUMS — WISCONSIN UPPER MICHIGAN SYSTEM
- ILL MO — ILLINOIS MISSOURI

MAAC MID ATLANTIC AREA COUNCIL

MARCA MID CONTINENT AREA RELIABILITY COORDINATION AGREEMENT

NPCC NORTHEAST POWER COORDINATING COUNCIL
- NEPOOL — NEW ENGLAND POWER POOL
- NYPP — NEW YORK POWER POOL

SERC SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
- VACAR — VIRGINIA CAROLINAS
- TVA — TENNESSEE VALLEY AUTHORITY
- SOUTHERN — SOUTHERN COMPANIES
- FLORIDA — FLORIDA

SWPP SOUTHWEST POWER POOL

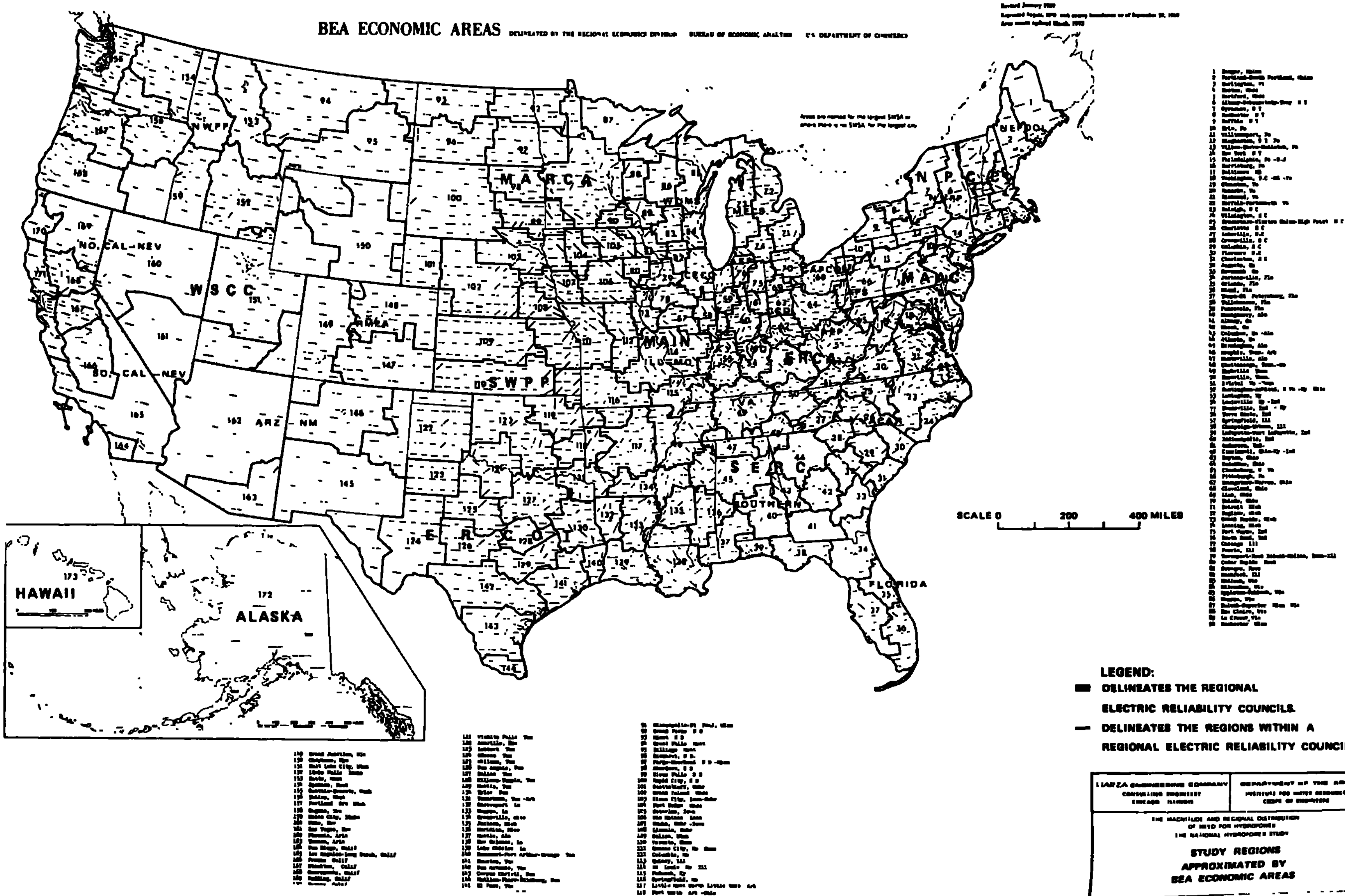
ERCOT ELECTRIC RELIABILITY COUNCIL OF TEXAS

WSCC WESTERN SYSTEMS COORDINATING COUNCIL
- NWPP — NORTHWEST POWER POOL AREA
- RMPA — ROCKY MOUNTAIN POWER AREA
- AZ NM — ARIZONA NEW MEXICO POWER AREA
- SO CAL NEV — SOUTHERN CALIFORNIA NEVADA POWER AREA
- NO CAL NEV — NORTHERN CALIFORNIA NEVADA POWER AREA

ALASKA

HAWAII

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY STUDY REGIONS APPROXIMATED BY UTILITY SERVICE AREAS	
CONTRACT NO. [illegible] DATE MARCH [illegible]	EXHIBIT [illegible]



LEGEND:

▬ DELINEATES THE REGIONAL ELECTRIC RELIABILITY COUNCILS.

— DELINEATES THE REGIONS WITHIN A REGIONAL ELECTRIC RELIABILITY COUNCIL.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

STUDY REGIONS APPROXIMATED BY BEA ECONOMIC AREAS

DATE MARCH 1979

EXHIBIT 1-2

East Central Area Reliability Coordination Agreement (ECAR)
Allegheny Power System (APS) - 19,65,66.
American Electric Power (AEP) - 20,51,52,64,76.
Central Area Power Coordination Group (CAPCO) - 67,68,70.
Cincinnati Columbus Dayton Group (CCD) - 62,63,69.
Michigan Electric Coordinated System (MECS) - 71,72,73,74.
Kentucky-Indiana (KY-IND) - 53,54,55,56,59,60,61,75.

Mid-America Interpool Network (MAIN)
Commonwealth Edison (CECO) - 77,79,82.
Wisconsin - Upper Michigan System (WUMS) - 83,84,85,86.
Illinois - Missouri (ILL-MO) - 57,58,78,112,113,114.

Mid-Atlantic Area Council (MAAC) - 10,11,13,14,15,16,17[1/].

Mid-Continent Area Reliability Coordination Agreement (MARCA) - 80,81,87,88,89,90,91,92,93,96,97,98,99,100,101,102, 103,104,105,106,107,108.

Northeast Power Coordinating Council (NPCC)
New England (NEPOOL) - 1,2,3,4,5.
New York Power Pool (NYPP) - 6,7,8,9,12,14[1/].

Southeastern Electric Reliability Council (SERC)
Virginia - Carolinas Subregion (VACAR) - 18,21,22,23,24,25, 26,27,28,29,30,31.
Tennessee Valley Authority (TVA) - 46,47,48,49,50.
Southern Companies Subregion (SOUTHERN) - 32,33,39,40,41, 42,43,44,45,136,137.
Florida Subregion (FLORIDA) - 34,35,36,37,38.

Southwest Power Pool (SWPP) - 109,110,111,115,116,117,118, 119,120,122,130,131,132,133,134,135,138,139,140.

Electric Reliability Council of Texas (ERCOT) - 121,123,124, 125,126,127,128,129,141,142,143,144.

Western Systems Coordinating Council (WSCC)
Northwest Power Pool Area (NWPP) - 94,95,151,152,153,154, 155,156,157,158,159.
Rocky Mountain Power Area (RMPA) - 147,148,149,150.
Arizona - New Mexico Power Area (ARZ-NM) - 145,146,162,163.
Southern California - Nevada Power Area (SO. CAL-NEV) - 161, 164,165,166.
Northern California - Nevada Power Area (NO. CAL-NEV) - 160, 167,168,169,170,171.

Alaska - 172.

Hawaii - 173.

1/ BEA 14 divided into two parts for analysis.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **LIST OF BEA ECONOMIC AREAS BY STUDY REGIONS**	
CONTRACT NO DACW72-78-C-0013 DATE MARCH, 1979	EXHIBIT I-3

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	ALABAMA		
1	Barry	1770 8 St	ALAP
		60 0 CT	ALAP
7	Chickasaw	138.0 St	ALAP
10	Colbert	1396 5 St	TVA
		475 8 CT	TVA
14	Fairfield	60 0 St	UNSS
17	Gadsden No 1 & 2	138 0 St	ALAP
20	Gorgas No 2	379 0 St	ALAP
21	Gorgas No 3	1166 7 St	ALAP
22	Guntersville	102 0 Hy	TVA
24	Jordan Dam	100 0 Hy	ALAP
25	Lay Dam	177 0 Hy	ALAP
27	Martin Dam	154 2 Hy	ALAP
		55 0 Hy*	ALAP
28	McWilliams	40 0 St	ALEC
29	Mitchell Dam	72 5 Hy	ALAP
		80 0 Hy*	ALAP
31	Mobile	44.0 St	SCPC
32	Mobile Mill	78 8 St	INPC
34	N. Birmingham Furn	25 0 St	USPF
36	Smith Dam	157 5 Hy	ALAP
38	Thurlow Dam	58 0 Hy	ALAP[1]
42	Wheeler Dam	356 4 Hy	TVA
43	Widows Creek	1978 0 St	TVA
44	Wilson Dam	629.8 Hy	TVA
46	Weiss	87 8 Hy	ALAP
47	Gaston, Ernest G	1060 8 St	SDEG
		952 0 St*	SOEG
		21 3 CT	SOEG
48	Yates	32 0 Hy	ALAP
49	Bankhead Lock 17	45 1 Hy	ALAP
50	Martin, Logan	128.3 Hy	ALAP
52	Greene County	568 5 St	ALAP[2]
53	Henry, H Neely	72 9 Hy	ALAP
54	Millers Ferry	75 0 Hy	USAR
55	Bouldin Dam	225 0 Hy	ALAP
56	Jones Bluff	68 0 Hy	USAR
57	Tombigbee	75 0 St	ALEC
		470 0 St*	ALEC
58	Browns Ferry	2304 0 Nu	TVA
		1152 0 Nu*	TVA
59	Holt Dam	40 0 Hy	ALAP
60	Demopolis	47 6 CT	ALAP
61	Farlye	1776 0 Nu*	ALAP
62	R L. Harris	135 0 Hy*	ALAP
63	J H Miller	2872 0 St*	ALAP
64	A R Barton	2416 0 Nu*	ALAP
65	Bellefonte	2664 0 Nu*	TVA

[1] 8 0 MW owned by Mt. Vernon Woodbury Mills, Inc
[2] Jointly owned by ALAP (60 percent) and MIPR (40 percent)

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	ALASKA		
2	Anchorage	78 9 CT	ANCO
3	Anchorage	40 0 CT	ANCO
		30 0 St*	ANCO
4	Beaver Falls	5 0 Hy	KECO
6	Eklutna	30 0 Hy	APAD
7	Chena	28 5 St	FACO
		32 9 CT	FACO
		8 3 IC	FACO
8	Gold Creek	1 6 Hy	ALEL
		8 2 IC	ALEL
9	Ketchikan	4 2 Hy	KECO
		0 9 IC	KECO
10	Knik Arm	14 5 St	CHEA[1]
11	Kodiak	24 9 IC	KOEA
22	Elmendorf – West	22 5 St	USAF
23	Fairbanks	40 7 CT	GOVE
		21 1 IC	GOVE
24	Blue Lake	6 0 Hy	SIPU
31	Wrangell	7 7 IC	WRLD
32	Cooper Lake	15 0 Hy	CHEA
34	Elmendorf – East	9 0 St	USAF
		2 1 IC	USAF
35	Ft Richardson	18 0 St	USAR
		7 2 IC	USAR
36	Fort Wainright	23 5 St	USAF
		3 5 IC	USAF
37	Eielson	15 0 St	USAF
		5 0 IC	USAF
38	Ft Greeley	6 3 IC	USAR
		2 0 Nu	USAR
45	Kodiak	4 0 St	USCG
		1 2 IC	USCG
47	Bernice Lake	27 8 CT	CHEA
55	International Station	47 3 CT	CHEA
58	Healy	25 0 St	GOVE
		2 8 IC	GOVE
59	Beluga	214 9 CT	CHEA
70	Lemon Creek	7 5 IC	ALEL
71	Snettisham	47 2 Hy	USAR
73	Ketchikan Pulp	38 6 St	KEPU
		0 8 IC	KEPU
74	Sitka	24 4 St	ALLU
75	Clear AFB	22 5 St	USAF
76	Adak	19 7 IC	USN & USAF
77	S W Bailey	11 0 IC	KECO
		4 5 IC*	KECO
79	Shemya	12 0 IC	USAF
80	Collier Kenai	9 7 IC	CDLL
81	Eyak	8 2 IC	COPU
82	North Pole	64 7 CT	GOVE
82	North Pole	64 7 CT*	GOVE
83	Valdez	10 1 IC	GOVE
84	Glennallen	7 6 IC	GOVE
85	Indian River	5 0 IC*	SIPU

[1] Jointly owned by CHEA & ALRR.

25Hz, etc. --Indicates frequencies other than 60 hertz; St--Steam, Nu--Nuclear; IC--Internal Combustion, Hy--Hydro; CT--Combustion Turbine; CC--Combined Cycle, * Under construction.

Note: Utility Codes are listed in Table on Exhibit I-5.

SOURCE: Department of Energy. "Principal Electric Facilities", DOE/EIA-0057/1-11, 1978

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

LIST OF POWER PLANTS IN THE UNITED STATES

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH, 1979
EXHIBIT I–4

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	ARIZONA		
1	Agua Fria	390.5 St	SARV
		223.0 CT	SARV
3	Phoenix	116.0 St	ARPS
		106.3 CT	ARPS
		396.0 CC[4]	ARPS
9	Cross Cut	3 0 Hy	SARV
		30.0 St	SARV
10	Davis	225 0 Hy	USBR
11	Demoss-Petrie	104.5 St	TUGE
		65.5 CT	TUGE
16	Glen Canyon	950.0 Hy	USBR
21	Horse Mesa	29 7 Hy	SARV
		100 0 Hy[3]	SARV
22	Inspiration	25.5 St 25Hz	INCC
25	Kyrene	108 0 St	SARV
		226.9 CT	SARV
32	Morenci Branch	108.0 St	PHDC
		31.0 IC	PHDC
33	Mormon Flat	9.2 Hy	SARV
		48.6 Hy[3]	SARV
35	New Cornelia	33 3 St	PHDC
37	Irvington	504.5 St	TUGE
		81.0 CT	TUGE
38	Roosevelt	36 0 Hy	SARV
40	Saguaro	250.0 St	ARPS
		106.3 CT	ARPS
51	Ocotillo	227.3 St	ARPS
		106.3 CT	ARPS
54	Yuma Axis	75 0 St	SOCE[1]
55	Cholla	113 6 St	ARPS
		860 0 St*	ARPS
57	Apache	85.0 CC[5]	AREP
		63.0 CT	AREP
		20.0 CT	AREP
		350.0 St*	AREP
58	Snowflake	27.2 St	SOFI
60	Navajo	2409 0 St	SARV[2]
61	Yucca (Yuma)	192.0 CT	ARPS
62	North Loop Station	108.0 CT	TUGE
63	Santan	414.0 CC	SARV
64	Coronado	1185.0 St*	SARV
65	Fairview	26 0 CT	ARPS
70	Palo Verde	3810.0 Nu*[6]	ARPS

[1] Joint ownership with, and operated by ARPS as agent.
[2] Jointly owned by SARV, USBR, ARPS, LOAN, NECP, & TUGE
[3] Pumped Storage Plant.
[4] Three Steam Units plus three CT Units. Total 225.0 MW continuous capability.
[5] One Steam Unit at 75 MW plus one CT at 10 MW. Each of the units can be operated independently.
[6] Jointly owned with SOCE, SARV, ELPE, & PSNM.

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	ARKANSAS		
4	Blakely Mountain	75 0 Hy	USAR[1]
6	Bull Shoals	340 0 Hy	USAR[1]
8	Carpenter	56 0 Hy	ARPL
9	Lynch, Cecil	259 8 St	ARPL
		5 5 IC	ARPL
12	Crossett (paper)	44 5 St	GEPA
14	Moses, Hamilton	138 0 St	ARPL
15	Couch, Harvey	187 5 St	ARPL
19	Jonesboro	27 7 St	JONE
		1 0 IC	JONE
20	Lake Catherine	756 5 St	ARPL
22	Narrows	25 5 Hy	USAR[1]
23	Norfork	70 0 Hy	USAR[1]
28	Remmel	9 3 Hy	ARPL
32	Beaver	112 0 Hy	USAR[1]
33	Dardanelle	124 0 Hy	USAR[1]
34	Greers Ferry	96 0 Hy	USAR[1]
35	Robert E Ritchie	906 6 St	ARPL
		18 9 CT	ARPL
36	Fitzhugh, Thos B	59 8 St	AREC
37	Degray	68 0 Hy	USAR[1]
38	Bailey, Carl E	120 0 St	AREC
39	McClellan, John	136 0 St	AREC
40	Ozark	100 0 Hy	USAR[1]
41	Ark Nuclear One (Russellville)	902 3 Nu	ARPL
		942 8 Nu*	ARPL
42	Mabelvale	75 6 CT	ARPL
43	Blytheville	213 6 CT	ARMP[2]
44	White Bluff	700 0 St*	ARPL
45	Flint Creek	528 0 St*	SOEP[3]

[1] Power marketing under Southwestern Power Administration
[2] Leased from Chrysler Financial Corp
[3] Jointly owned with Arkansas Elec Coop Corp

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	CALIFORNIA		
4	Alamitos	1982.4 St	SOCE
		138.1 CT	SOCE
12	Avon	40.0 St	PAGE
14	Balch 1 and 2	128.2 Hy	PAGE
16	Belden	117.9 Hy	PAGE
19	Big Creek No 1	67.0 Hy	SOCE
20	Big Creek No. 2	57.8 Hy	SOCE
21	Big Creek No. 2A	80.0 Hy	SOCE
22	Big Creek No. 3	106 5 Hy	SOCE
23	Big Creek No. 4	84.0 Hy	SOCE
24	Big Creek No. 8	58.5 Hy	SOCE

CALIFORNIA—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	CALIFORNIA—Continued		
31	Brawley	13.3 IC	IMID
		22.5 CT	IMID
32	Broadway	171.0 St	PASA
33	Bucks Creek	66.0 Hy	PAGE
35	Burbank	187.3 St	BURB[1]
		85.0 CT	BURB
36	Butt Valley	36.0 Hy	PAGE
37	Caribou No. 1	75.0 Hy	PAGE
38	Caribou No 2	109 8 Hy	PAGE
45	Contra Costa	1253.6 St	PAGE
46	Control Gorge	37.5 Hy	LOAN
48	Copco Two	27.0 Hy	PAPL
61	Cresta	67.5 Hy	PAGE
55	Donnells	64.0 Hy	OASJ & TUID
58	Drum 1 and 2 (2 plants)	93.3 Hy	PAGE[1]
61	El Centro	189.1 St	IMID
63	Electra	89.1 Hy	PAGE
64	El Segundo	996.5 St	SOCE
65	Encina	636 8 St	SADG
		18.0 CT	SADG
		292 0 St*	SADG
66	Etiwanda	911.0 St	SOCE
		138 1 CT	SOCE
68	Exchequer	80.1 Hy	MEID
72	Folsom	198.7 Hy	USBR
75	L. W. Grayson	163 0 St	GLPS
		53 0 CT	GLPS
		99.0 CT*	GLPS
76	Haas	135 0 Hy	PAGE
80	Harbor	388 9 St	LOAN
		94.3 CT	LOAN
83	Highgrove	169.0 St	SOCE
84	Humboldt Bay	102.4 St	PAGE
		65.3 Nu	PAGE
85	Hunters Point	356.3 St	PAGE
		45.6 CT	PAGE
86	Huntington Beach	870.4 St	SOCE
		138.1 CT	SOCE
92	Kerckhoff	34.1 Hy	PAGE
93	Kern	152.0 St	PAGE
97	Kern River No. 3	32.0 Hy	SOCE
98	Keswick	75.0 Hy	USBR
100	Kings River	44.1 Hy	PAGE
104	Long Beach	490.0 CC[6]	SOCE
		100.0 St	SOCE
		112.0 St[7]	SOCE
108	Mandalay	436.2 St	SOCE
		138.1 CT	SOCE
109	Martinez	40.0 St	PAGE
113	Middle Gorge	37.6 Hy	LOAN
117	Moccasin	90.0 Hy	SAFH
118	Morro Bay	1056.3 St	PAGE
	CALIFORNIA—Continued		

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	CALIFORNIA—Continued		
119	Moss Landing	2152.1 St	PAGE
125	Oleum	80.0 St	PAGE
127	Parker	120.0 Hy	USBR
128	Glenarm	65.3 St	PASA
		57.6 CT	PASA
130	Pilot Knob	33.0 Hy	IMID
131	Pit No. 1	56.0 Hy	PAGE
132	Pit No. 3	80.2 Hy	PAGE
133	Pit No. 4	90.0 Hy	PAGE
134	Pit No. 5	140.6 Hy	PAGE
135	Pittsburg	2028.9 St	PAGE
137	Poe	142.9 Hy	PAGE
140	Potrero	317.9 St	PAGE
		153.5 CT	PAGE
144	Redondo Beach 1 and 2	1579.4 St	SOCE
146	Rock Creek	113.4 Hy	PAGE
148	Salt Springs	39.0 Hy	PAGE
150	San Bernadino	130.6 St	SOCE
152	San Francisquito No. 1	58.1 Hy	LOAN
153	San Francisquito No. 2	42.0 Hy	LOAN
162	Scattergood	823.2 St	LOAN
164	Shasta	452.3 Hy	USBR
166	Silver Gate	247.0 St	SADG
172	Stanislaus	81.9 Hy	PAGE
173	Station B	93.0 St	SADG
174	Tiger Creek	51.0 Hy	PAGE
177	Trona	45 1 St	KECH
179	Upper Gorge	37.6 Hy	LOAN
181	Valley	545.6 St	LOAN
191	Camino	142.5 Hy	SAMU
192	Holm, D. R.	135.0 Hy	SAFH
193	Coolwater	146.9 St	SOCE
		196.0 St*[8]	SOCE
		276.0 CT*[8]	SOCE
194	Geysers	624.7 St	PAGE
		297.0 St*	PAGE
195	Jaybird	133.0 Hy	SAMU
196	Mammoth Pool	129.4 Hy	SOCE
197	South Bay	713.9 St	SADG
		18.6 CT	SADG
198	Trinity	105.6 Hy	USBR
199	Union Valley	33 3 Hy	SAMU
200	Haynes	1606.0 St	LOAN
203	Judge F. Carr	141.4 Hy	USBR
204	Spring Creek	150.0 Hy	USBR
205	Woodleaf	52.2 Hy	ORWI
206	Forbestown	28.8 Hy	ORWI
208	Edward G. Hyatt	644.3 Hy	CADW
210	Thermolito	115.1 Hy	CADW
212	Black, J. B.	154.8 Hy	PAGE
	CALIFORNIA—Continued		

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	CALIFORNIA—Continued		
213	Pit 6	79.2 Hy	PAGE
214	Pit 7	104.4 Hy	PAGE
216	Kirkwood, R. C.	67.5 Hy	SAFH
217	White Rock	190.0 Hy	SAMU
218	San Onofre	450.0 Nu[2]	SOCE[3]
		2360.0 Nu*	SOCE[3]
219	Ralston	79.2 Hy	PLWA
220	Middle Fork	109.8 Hy	PLWA
222	Chicago Park	37.4 Hy	NEID
229	O'Neill	25.2 Hy	USBR
230	San Luis	424.0 Hy	USBR[4]
231	Loon Lake	74.1 Hy	SAMU
232	Diablo Canyon	2120.0 Nu*	PAGE
233	Kearny Substation	164.7 CT	SADG
234	Colgate	284.4 Hy	YUBA
235	Narrows	46.8 Hy	YUBA
237	Rancho Seco	928.0 Nu	SAMU
238	Castaic	693.5 Hy	LOAN
		637.5 Hy*	LOAN
239	Miramar	39.1 CT	SADG
240	North Island	39.1 CT	SADG
241	Pittsburg	48.0 CT	DOCC
242	Samoa	47.5 St	LAPA
243	Ormond Beach	1612.8 St	SOCE
244	Devil Canyon	120.0 Hy	CADW
245	Coachella	92.6 CT	IMID
246	New Melones	300.0 Hy*	USBR
247	Ellwood	56.7 CT	SOCE
248	Oakland	189.0 CT*	PAGE
249	Helms PS	1053.0 Hy*	PAGE
250	Naval Station	28.3 CT	SADG

[1] Represents two adjacent plants.
[2] Operated by SOCE.
[3] Jointly owned by SOCE and SADG.
[4] Jointly owned by USBR and CADW.
[5] Includes Lewiston Plant — 0.6 MW.
[6] 1 St Unit 80.0 MW, 1 St Unit 60.0 MW, 7 CT Units, 50.0 MW each.
[7] Cap increase for 2 existing St Units.
[8] 2 CC Units at 236.0 MW each.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	COLORADO		
4	Arapahoe	250 5 St	PSCO
9	Cameo	75.0 St	PSCO
10	Clark, W. N	43.8 St	CETU[1]
12	Cherokee	801 3 St	PSCO
		5.5 IC	PSCO
13	Drake, Martin	282.3 St	COSP
16	Estes	45.0 Hy	USBR
18	Flatiron	71.5 Hy	USBR
20	Birdsall, George	62 5 St	COSP
30	Lamar	32.5 St	LALP
		2.2 IC	LALP
39	Minnequa	48.8 St	COFI
41	Nucla Springs	34 5 St	COUE
44	Pole Hill	33.3 Hy	USBR
45	Pueblo	32 3 St	CETU
		10 0 IC	CETU
	COLORADO—Continued		
60	Valmont	281 8 St	PSCO
		65 3 CT	PSCO
65	Zuni	115 3 St	PSCO
71	Blue Mesa	60 0 Hy	USBR
72	Morrow Point	120 0 Hy	USBR
73	Hayden	465 0 St	COUE[2]
74	Cabin Creek	300 0 Hy	PSCO
75	Crystal	28 0 Hy*	USBR
76	Ft St Vrain	343.0 Nu*	PSCO
77	Comanche	778 5 St	PSCO
78	Mt Elbert	200 0 Hy*	USBR
79	Alamosa	18 9 St	PSCO
		58 0 CT	PSCO
80	Fruita	28 8 CT	PSCO
81	Fort Lupton	100 8 CT	PSCO
82	Craig	770 0 St*	COUE[3]
83	Republican River	224 7 CT	TRGT
84	Nixon, Ray D.	200 0 St*	COSP
85	Burlington	100 0 CT*	TRGT
86	Pawnee*	522 0 St*	PSCO

[1] 18 8 MW leased from Colorado-Ute Electric Assn.
[2] Joint ownership with SARV
[3] Craig is jointly owned by COUE, TRGT, SARV and PRPA.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	CONNECTICUT		
1	Bridgeport Harbor	660.5 St	UNIC
		18 6 CT	UNIC
5	Devon	454.0 St	COLP
		16 3 CT	COLP
8	English	145.3 St	UNIC
11	Middletown	836.9 St	HAEL
		18.6 CT	HAEL
12	Montville	577 4 St	COLP
		5.5 IC	COLP
14	Norwalk Harbor	326 4 St	COLP
		16.3 CT	COLP
18	Rocky River	31.0 Hy[2]	COLP
20	Shepaug	37.2 Hy	COLP
22	South Meadow	177.4 CT	HAEL
24	Steel Point	155 5 St	UNIC
26	Stevenson	30 5 Hy	COLP
44	Haddam Neck	600.3 Nu	COYA
45	Millstone	1571.5 Nu	COLP[1]
		1150.0 Nu*	COLP[4]
51	Cos Cob	63.8 CT	COLP
54	New Haven Harbor	464 6 St	UNIC[3]

[1] Jointly owned by HAEL, COLP, & WEME, and operated by Northeast Nuclear Energy Company.
[2] Pumped Storage.
[3] Jointly owned by UNIC, FIGE, and HOLM.
[4] Jointly owned by COLP, HAEL, WEME, NEEP, and others, and operated by Northeast Nuclear Energy Company.

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	DELAWARE		
2	Delaware City	129 7 St	DEPL
		18 6 CT	DEPL
4	Edge Moor	836 2 St	DEPL
		12 5 CT	DEPL
5	Indian River	340 0 St	DEPL
		445 5 St*	DEPL
		18.6 CT	DEPL
11	McKee Run	171 5 St	DODE
12	Christiana	53 3 CT	DEPL
	DISTRICT OF COLUMBIA		
1	Benning	747 6 St	POEP
2	Buzzard Point	270.0 St	POEP
		288.0 CT	POEP
	FLORIDA		
2	Avon Park	46.0 St	FLPC
		67 6 CT	FLPC
3	Bayboro	227 0 CT	FLPC
7	Crist	1229 0 St	GUPC
8	Cutler	351 5 St	FLPL
14	Fort Myers	558 3 St	FLPL
		638 2 CT*	FLPL
15	King, Henry D.	124 0 8 St	FOPC
		5 5 IC	FOPC
16	Gannon, Francis J	1270 4 St	TAEC
		18 0 CT	TAEC
17	Kelly, John R.	99 0 St	GAMW
		43 5 CT	GAMW
		1 2 IC	GAMW
18	Turner, George E	189 6 St	FLPC
		181 0 CT	FLPC
19	Higgins	138 0 St	FLPC
		153.4 CT	FLPC
21	Hookers Point	232 6 St	TAEC
26	Woodruff, Jim	30.0 Hy	USAR[1]
29	Key West	70 0 St	KEWU
		6 4 IC	KEWU
33	Larsen (Lake Parker)	120 0 St	LALW
		33 8 CT	LALW
34	Lauderdale	312 5 St	FLPL
		821 4 CT	FLPL
35	Smith, Tom G	22.6 IC	LAWU
		74 1 St	LAWU
39	Miami	46.0 St	FLPL
42	New Smyrna Beach	10 7 IC	NESB
		7 5 St	NESB
44	Lake Highland	103 8 St	ORLA
		37 5 CT	ORLA
		1.0 IC	ORLA
46	Palatka	109.5 St	FLPL
47	Panama City	44 5 St	INPC
48	Bartow, Paul L.	494 4 St	FLPC
		222 8 CT	FLPC
53	Port St Joe	40.5 St	SAJP
55	Riviera	739 6 St	FLPL
58	Sam O. Purdom	130 0 St	TALL
		30.0 CT	TALL

FLORIDA—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	FLORIDA—Continued		
59	Sanford	1028.5 St	FLPL
61	Scholz	98.0 St	GUPC
63	Southside	356.6 St	JACO
		34 0 CT	JACO
65	Suwanee	147.0 St	FLPC
66	Kennedy, J. Dillon	249.6 St	JACO
		258.0 CT	JACO
68	Vero Beach	13 4 IC	VEBM
		62 0 St	VEBM
		56.0 St	VEBM
73	Indian River	611 3 St	ORLA
75	Port Everglades	1254 6 St	FLPL
		13 8 IC	FLPL
		410 7 CT	FLPL
76	Smith, Lansing	340 0 St	GUPC
		41 8 CT	GUPC
78	Cape Canaveral	804 0 St	FLPL
79	Crystal River	964 3 St	FLPC
		1200 0 St*	FLPC
		860 4 Nu*	FLPC
80	Northside	1045 0 St	JACO
		563 7 St*	JACO
		32 6 CT	JACO
		200 0 CT	JACO
82	Turkey Point	804 1 St	FLPL
		13 8 IC	FLPL
		1519 9 Nu	FLPL
84	Big Bend	486 0 St*	TAEC
		175 5 CT	TAEC
		891 0 St	TAEC
85	McIntosh Plant	0.2 33 0S T	
			& LALW
		250 0 St*	LALW
		5 5 IC	LALW
		26 6 CT	LALW
86	Hopkins	75 0 St	TALL
		259 0 St*	TALL
		43 3 CT	TALL
87	St Lucie	850.0 Nu*	FLPL
		850 0 Nu	FLPL
88	Anclote	515.0 St	FLPC
		556.2 St*	FLPC
89	Deerhaven	75 0 St	GAMW
		40 0 CT*	GAMW
		250 0 St*	GAMW
90	Manatee	1726 0 St*	FLPL
		863.0 St	FLPL
91	Stock Island	37 0 St	KEWU
		6 0 IC	KEWU
92	Martin	1726.0 St*	FLPL
93	Saint Lucie County	75 0 St*	FOPC
94	Debary	401 4 CT	FLPC
95	Putnam	580 0 CC*	FLPL
		290 0 CC	FLPL
96	Ellis, R F	1105 0 St*	GUPC
97	South Dade	1300.0 Nu*	FLPL
98	MacInnes, W C.	486 0 St*	TAEC

[1] Power marketing under Southeastern Power Administration

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GEORGIA

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
1	Allatoona	74 0 Hy	USAR[1]
2	Arkwright	181 3 St	GEPC
		32.6 CT	GEPC
3	Atkinson	258 0 St	GEPC
		83 7 CT	GEPC
7	Bartletts Ferry	65 0 Hy	GEPC
		100 0 Hy*	GEPC
10	Buford	86 0 Hy	USAR
20	Goat Rock	26 0 Hy	GEPC
		68 0 Hy*	GEPC
22	Hammond	953 0 St	GEPC
23	Hartwell	264 0 Hy	USAR[1]
29	McManus	143 8 St	GEPC
		2 0 IC	GEPC
		498 6 CT	GEPC
33	North Highlands	29 6 Hy	GEPC
35	Oliver	60.0 Hy	GEPC
37	Port Wentworth	328 2 St	SAEP
		21.6 CT	SAEP
38	Riverside	111 0 St	SAEP
40	Sinclair Dam	45 0 Hy	GEPC
43	Tallulah Falls	72 0 Hy	GEPC
46	Tugalo	45 0 Hy	GEPC
		125.6 CT	GEPC
49	Mitchell, Wm.	218 3 St	GEPC
50	Yates	1083 8 St	GEPC
		403 8 St*	GEPC
52	McDonough	598.4 St	GEPC
		83 7 CT	GEPC
53	Carters	250 0 Hy	USAR
		250 0 Hy*	USAR
54	Branch, Harllee	1746 2 St	GEPC
55	George, W. F.	130 0 Hy	USAR[1]
57	West Point	73 4 Hy*	USAR
58	Bowen, H. L.	2546 6 St	GEPC
		952 0 St*	GEPC
		41 8 CT	GEPC
59	Hatch	850 0 Nu	GEPC
		850 0 Nu*	GEPC
60	Boulevard	52.0 CT*	SAEP
61	Effingham	413.0 St*	SAEP
62	Wallace	324 0 Hy*	GEPC
63	Voctle	2430 0 Nu*	GEPC
		318 8 CT	GEPC
64	Wansley	952 0 St*	GEPC
		952 0 St	GEPC
65	Rocky Mountain	675.0 Hy*	GEPC
66	Scherer	3564 0 St*	GEPC
67	Russell, R B.	300 0 Hy*	USAR

[1] Power marketing under Southeastern Power Administration.

HAWAII

Plant No	Name of Plant	MW Capacity and Type	Utility Code
4	Honolulu (2 plants)	168 2 St	HAEC
7	Kahului	34 0 St	MAEC
8	Waimea	10 5 IC	HELC
10	Kaunakakai	8 8 IC	MOEC
12	Waipahu	16 5 St	OASC
14	Paia Mill	8 0 St	HACS[1]
15	Puunene Mill	24 0 St	HACS
16	Puueo	2 3 Hy	HELC
		3.0 IC	HELC
17	Shipman & W. H. Hill	60.5 St	HELC
18	Waialua Mill	12 0 St	WASC
19	Waiau	394 5 St	HAEC
		102 6 CT	HAEC
23	Kekaha	6 5 St	KESC
29	Lihue	10.0 St	LIPC
32	Koloa Mill	15 0 St	MBSC
33	Kahe	474 9 St	HAEC
35	Kanoelehua	11 7 CT	HELC
		9 5 IC	HELC
38	Ookala	6 0 St	LASC
41	Olaa	15 0 St	PUSC
45	Lahaina (Mill)	12 3 St	PIMC
47	Port Allen	10.0 St	CIUC
		17 7 CT	CIUC
		11.5 IC	CIUC
49	Maalaea	29 9 IC	MAEC
51	Keahole	5 0 IC	HELC
52	Pepeekeo	23.8 St	HICP
53	Honokaa	7.5 St	HOSC
		0.8 Hy	HOSC

[1] One 4 0 MW Unit is jointly owned with MAEC

IOAHO

Plant No	Name of Plant	MW Capacity and Type	Utility Code
1	Albeni Falls	42 6 Hy	USAR
2	American Falls	93.0 Hy*	IDPC
3	Anderson Ranch Dam	27 0 Hy	USBR
7	Bliss	75 0 Hy	IDPC
9	Brownlee	360 4 Hy	IDPC
		225 0 Hy*	IDPC
10	Cabinet Gorge	200 0 Hy	WAWP
12	Strike, C. J.	82 8 Hy	IDPC
17	Grace	33 0 Hy	UTPL
24	Lower Salmon	60.0 Hy	IDPC
28	Oneida	30 0 Hy	UTPL
29	Palisades	118 8 Hy	USBR
41	Upper Salmon	34.5 Hy	IDPC
42	Dworshak	310 0 Hy	USAR
44	Wood River	50 0 CT	IDPC

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EXHIBIT I-4

Plant No	Name of Plant	MW Capacity and Type	Utility Code
		ILLINOIS	
1	Abbott	30 0 St	UNIL
8	Argo	27 0 St	CORC
15	Cahokia	304 0 St	UNEC
16	Calumet	288 0 CT	COEC
21	Crawford	597 5 St	COEC
		192 0 CT	COEC
26	Dixon	3 2 Hy	COEC
		119 0 St	COEC
28	Dresden	1865 3 Nu	COEC
33	Fisk	546 6 St	COEC
		10 0 IC	COEC
		226 1 CT	COEC
40	Grand Tower	179 6 St	CEIP
47	Havana	230 0 St	ILPC
		450 0 St*	ILPC
48	Hennepin	306 3 St	ILPC
50	Hutsonville	200 0 St	CEIP
		2 8 IC	CEIP
52	Jacksonville	7 8 IC	JAVI
		18 0 CT	JAVI
53	Joliet	1787 4 St	COEC
		144 0 CT	COEC
		10 0 IC	COEC
57	Joppa	1100 3 St	ELEN
59	Lakeside	155 0 St	SPFI
67	Meredosia	564 4 St	CEIP
68	Moline	3 6 Hy	IOIG
		104 7 St	IOIG
		40 0 CC	IOIG
		72 0 CT	IOIG
76	Ottawa	31 9 St	LIDF
79	Peru	15 3 St	PERU
		6 3 IC	PERU
		11 5 CT	PERU
81	Powerton	1785 6 St	COEC
85	Ridgeland	690 0 St	COEC
92	Wallace, R S	305 0 St	CEIL
93	Sabrooke	144 0 CT	COEC
100	Southwest	30 5 St	CHSD
101	South	105 0 St	UNSS
		20 4 IC	UNSS
110	Venice	474 0 St	UNEC
		37 5 CT	UNEC
111	Vermilion	182 3 St	ILPC
		15 0 CT	ILPC
114	Waukegan	932 8 St	COEC
		113 0 CT	COEC
115	Will County	1268 9 St	COEC
117	Winnetka	25 5 St	WINK
118	Wood River	650 1 St	ILPC
122	Edwards E D	779 8 St	CEIL
126	Marion	99 0 St	SOIP
		173 0 St*	SOIP
127	Pearl	27 2 St	WEIL
		26 6 CT	WEIL
128	Coffeen	1005 5 St	CEIP
129	Kincaid	1319 4 St	COEC
130	Quad Cities	1656 6 Nu	COEC[1]
131	Zion	2196 0 Nu	COEC
132	Baldwin	1893 6 St	ILPC
133	Lombard	111 6 CT	COEC
134	Electric Junction	288 0 CT	COEC
135	Black Duck	417 0 St	CEIL
136	Sterling Avenue	32 0 CT	CEIL
137	Dallman	180 5 St	SPFI
		192 0 St*	SPFI
138	LaSalle County	2293 4 Nu*	COEC
139	Bloom TSS	157 0 CT	COEC
140	Oglesby	70 2 CT	ILPC
141	Stallings	95 2 CT	ILPC
142	Highland	12 5 St	HIGH
		12 9 IC	HIGH
143	Rochelle	11 5 St	ROCL
		18 5 IC	ROCL
144	Collins	2601 3 St*	COEC

ILLINOIS—Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
		ILLINOIS Continued	
145	Factory	26 6 CT	SPFI
146	Byron	2350 0 Nu*	COEC
147	Newton	600 0 St*	CEIP
148	Duck Creek	416 0 St	CEIP
149	Braidwood	2350 0 Nu*	COEC
150	Clinton	950 0 Nu*	ILPC[2]

[1] Jointly owned by COEC and IOIG
[2] Jointly owned with WEIL (50 000) and SOPC (80 000)

Plant No	Name of Plant	MW Capacity and Type	Utility Code
		INDIANA	
4	Bread	450 0 St	INME
6	Charlestown	55 0 St	ICIU
7	Clifty Creek	1303 6 St	INKE
9	Mitchell Dean H	529 4 St	NOIP
		52 2 CT	NOIP
13	Edwardsport	146 8 St	PSIN
15	Culley F B	414 9 St	SOIG
16	Frankfort	32 5 St	FRAF
		16 5 CT	FRAF
17	Gary	60 0 St	UNSS
		45 0 IC 25Hz	UNSS
19	Stout E W	854 6 St	INPL
		79 9 CT	INPL
		2 8 IC	INPL
21	Indian Harbor	99 4 St	YOST
26	Lawton Park	30 0 St	INME
27	Logansport	43 0 St	LOSP
		18 0 CT	LOSP
28	Michigan City	736 0 St	NOIP
32	Gallagher R A	600 0 St	PSIN
34	Noblesville	100 0 St	PSIN
37	Ohio River	171 5 St	SOIG
		53 1 CT	SOIG
38	Perry Sac K	47 5 St	INPL[1]
40	Peru	40 0 St	PERI
47	State Line	968 0 St	COED
48	Tanners Creek	1098 0 St	INME
51	Twin Branch	237 5 St	INME
		7 3 Hy	INME
54	Wabash River	962 0 St	PSIN
		8 2 IC	PSIN
57	Pritchard H T	393 6 St	INPL
		2 7 IC	INPL
58	White Water Valley	90 0 St	RICI
60	Chicago	212 5 St	INST
61	Bailly	615 6 St	NOIP
		33 9 CT	NOIP
		685 0 Nu*	NOIP
62	Warrick	731 0 St	ALCO[2]
68	Petersburg	724 4 St	INPL
		8 2 IC	INPL
		532 0 St*	INPL
67	Markland	64 8 Hy	PSIN
68	Cayuga	1062 0 St	PSIN
		11 4 IC	PSIN
69	Miami Wabash Peaking Station	104 6 CT	PSIN
70	Ratts F E	233 2 St	INSR
72	Indiana Mobiles	51 0 CT	INME
73	Gibson	1484 0 St	PSIN
75	Connersville	83 7 IC	PSIN
76	Schahfer R M	520 8 St	NOIP
		556 0 St*	NOIP
77	Whiting Refinery	63 7 St	AMOC
78	Brown A B	265 0 St*	SOIG

[1] Including 2 units one of 2 000 and one of 1 000 KW owned by this plant and operated in 2 industrial plants through 2 high pressure steam pipeline
[2] Unit No 4 (323 MW) jointly owned by SOIG and ALCO

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	IOWA		
4	Ames	63.7 St	AMES
		1 0 IC	AMES
		22 0 CT	AMES
8	Kapp, M L.	237 2 St	INPD
11	Big Sioux	41 0 St	IOPS
13	Boone	34 3 St	IOEL
14	Bridgeport	71 0 St	IOSU
19	Cedar Falls	66 5 St	CEFA
		19 6 CT	CEFA
20	Cedar Rapids	92.3 St	IOEL
22	Parr	36.0 CT	IOPS
26	Coralville	72 0 CT	IOIG
28	Council Bluffs	130.6 St	IOPL
		650 0 St*[4]	IOPL
36	Des Moines No 2	269 6 St	IOPL
41	Dubuque	81 2 St	INPD
		4.6 IC	INPD
65	Humboldt	43.8 St	COBP
74	Keokuk	128.0 Hy	UNEC
79	Lansing	324 0 St	INPD
		2 0 IC	INPD
		260.0 St*	INPD
89	Maynard	77 4 St	IOPS
94	Muscatine	125 0 St	MUSC
109	Prairie Creek	244 7 St	CEIC[1]
113	Riverside	221 7 St	IOIG
		72 0 CT	IOIG
128	Summit Lake	22 5 St	CEIC
		60.0 CT	CEIC
		5.8 IC	CEIC
129	Sutherland	156 6 St	IOEL
144	Wisdom, Earl	37.5 St	COBP
155	Fair, F. E	62 5 St	EAIL
169	George Neal	1046 3 St	IOPS[3]
		5 5 IC	IOPS
		585 0 St*[5]	IOPS
171	Burlington	212 0 St	IOSU
		106 0 CT*	IOSU
173	River Hills	124 0 CT	IOPL
174	Duane Arnold	530 0 Nu	IOEL[2]
175	Pella	43 5 St	PELL
176	Webster City	15.4 St	WECI
		20 0 CT	WECI
178	Sycamore	157.5 CT	IOPL
179	Electrifarm	71 2 CT	IOPS
		74 0 CT*	IOPS
180	Clinton	27 0 St	CLCC
181	Indianola	20 6 CT	INDI
		14 1 IC	INDI

[1] Operated by Iowa Electric Light and Power Company
[2] Jointly owned by IOEL, COBP and CEIC
[3] Unit No 3 (550 MW) jointly owned by IOIG, IOPL and IOSU.
[4] Jointly owned by IOPL, IOIG, EAIL, COBP, CEIC and 2 municipals
[5] Jointly owned by IOPS, INPD, NOIO, NOPS, COBP and 8 municipals.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	KANSAS		
3	Mullergren, Arthur	119 1 St	CETU
15	Coffeyville	80 1 St	COFF
25	Judson	179 5 CT	CETU
27	Garden City	120.4 St[2]	SUNC
		87.2 CT	SUNC
45	Hutchinson No 2	257 2 St	KAPL
		342.6 CT	KAPL
50	Kaw Station	161.3 St	KACY
55	Lawrence	613 4 St	KAPL
64	McPherson No. 1	25 5 St	MCPH
		1.0 IC	MCPH
68	Gill, Murray	348 3 St	KAGE
70	Neosho	113.5 St	KAGE
78	Ottawa	6 5 St	OTTA
		7 3 IC	OTTA
		11.8 CT	OTTA
81	Pratt	23.8 St	PRAT
		1.5 IC	PRAT
83	Quindaro	333 6 St	KACY
		142.4 CT	KACY
84	Ripley	87.3 St	KAGE
85	Abilene	33.8 St	KAPL
		77.8 CT	KAPL
86	Riverton	32.5 St 25Hz	EMDE
		112.5 St	EMDE
		12.5 CT	EMDE
88	Ross Beach	11.5 St	CEKP
		25 0 St	SUNC[1]
100	Tecumseh	346 1 St	KAPL
		53.3 CT	KAPL
108	Winfield	44 5 St	WINF
		11 3 CT	WINF
109	Evans, Gordon	539 3 St	KAGE
115	Cimmaron River	50.0 St	CETU
		15 0 CT	CETU
116	McPherson No 2	32.0 St	MCPH
		130.5 CT	MCPH
117	Wellington	33 5 St	WELL
		1.0 IC	WELL
118	Lacygne	1558 7 St	KAGE[3]
119	Colby	12 0 St	CEKP
		16 3 CT	CEKP
		2 8 IC*	CEKP
120	Clifton	85 0 CT	CETU
		3 0 IC	CETU
121	Jeffrey Energy Center	1440 0 St*	KAPL
122	Nearman Creek	250 0 St*	KACY
123	Wolf Creek	1150 0 Nu*	KAGE[3]

[1] Leased to and operated by Central Kansas Power Co
[2] 12 5 MW owned by Garden City, Kansas
[3] Jointly owned by KAGE and KACP.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	KENTUCKY		
3	Cane Run	1016 7 St	LOGE
		16.3 CT	LOGE
4	Dix Dam	28 3 Hy	KEUC
6	Brown, E W	724 1 St	KEUC
8	Green River	263.7 St	KEUC
10	Henderson	50.6 St	HEND
		2 5 IC	HEND
11	Kentucky Dam	175 0 Hy	TVA
15	Ohio Falls	80 3 Hy	LOGE
16	Owensboro	49 5 St	OWEN
17	Paddys Run	337 5 St	LOGE
		48.6 CT	LOGE
19	Pineville	37 5 St	KEUC
20	Shawnee	1750 0 St	TVA
21	Tyrone	137 5 St	KEUC
22	Waterside	45 0 CT	LOGE
23	Dale, Wm. C.	196 0 St	EAKR
24	Wolf Creek	270 0 Hy	USAR
25	Barkley	130.0 Hy	USAR
26	Paradise	2558 2 St	TVA
27	Big Sandy	1096 8 St	KEPC
28	Cooper, John Sherman	344 0 St	EAKR
29	Smith, Elmer	416 0 St	OWEN
30	Reid	80 0 St	BIRI
		480 0 St*	BIRI
		66 0 CT	BIRI
31	Coleman	521 3 St	BIRI
32	Spurlock, H. L.	800 0 St*	EAKR
33	Ghent	1112 9 St	KEUC
		1112 0 St*	KEUC
34	Haefling	62 1 CT	KEUC
35	Laurel	61 0 Hy*	USAR
36	Mill Creek	711 0 St	LOGE
		920 0 St*	LOGE
37	Power Station Two	350 0 St	HEND
	LOUISIANA		
1	Patterson, A B	224 0 St	NEOP
		16 0 CT	NEOP
3	Arsenal Hill	170 0 St	SOEP
6	Coughlin	483 3 St	CELE
12	Houma	18 0 IC	HOUM
		12 0 CT	HOUM
		86 7 St	HOUM
15	Rodemacher	46 5 St	LAFA
		2 8 IC	LAFA

LOUISIANA Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	LOUISIANA–Continued		
16	Lake Charles	50 0 St	CISR
17	Lake Charles	90 0 St	PIPG
19	Lieberman	277 3 St	SOEP
20	Louisiana	428 0 St	GUSU
22	Market Street	96 3 St	NEOP
24	Michoud	959 3 St	NEOP
25	Bogalusa Mill	42 0 St	CRZE
26	Minden	13 8 IC	MIND
		25 0 St	MIND
27	Monroe	166 0 St	MONR
		10 0 CT	MONR
28	Morgan City	9 7 IC	MOCI
		67 0 St	MOCI
29	Natchitoches	42 0 St	NATC
		10 4 IC	NATC
30	Nelson, Roy S	982 3 St	GUSU
33	Nine Mile Point	1917 3 St	LOPL
35	Opelousas	12 0 IC	OPEL
		38 7 St	OPEL
38	Power House No 2	41 0 St 25Hz	NEOS
		20 0 CT 25Hz	NEOS
42	Riverside	166 2 St	PIPG
44	Springhill	46 3 St	INPC
45	Sterlington	291 5 St	LOPL
		130 6 CT	LOPL
		101 3 CC	LOPL
46	Teche	427 9 St	CELE
48	Chalmette	398 0 St	KACC
		103 2 IC[2]	KACC
50	Little Gypsy	1250 8 St	LOPL
51	Louisiana	221 7 St	DOCC
52	Willow Glen	2178 2 St	GUSU
53	Alexandria No 2	173 7 St	ALEX
54	McDonald Ave	81 0 St	RUST
55	Bonin, Doc	339 5 St	LAFA
56	Thibodaux No 2	30 8 IC	LOPL
		21 0 St	LOPL
57	Allied Chemical	70.6 CT	GUSU[1]
58	Big Cajun No 1	230 0 St	CAJU
60	Plaquemine	10 8 IC	PLAQ
		20 0 St	PLAQ
61	Rodemacher	445 5 St	CELE
		558 0 St*	CELE
62	Waterford	891 0 St	LOPL
		1165 0 Nu*	LOPL
63	Franklin	15 5 IC	FRAN
		10 0 CT	FRAN
64	River Bend	1036 0 Nu*	GUSU
65	Big Cajun No 2	1080 0 St*	CAJU

[1] Leased to Allied Chemical Corp
[2] Direct Current (DC) Generator

HARZA ENGINEERING COMPANY
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EXHIBIT I–4

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	MAINE		
10	Cape	22.5 St	CEMP
		35.1 CT	CEMP
11	Caribou	0 8 Hy	MAPS
		19.0 St	MAPS
		8.1 IC	MAPS
13	Wyman	213.6 St	CEMP
		600.0 St*	CEMP[1]
23	Graham	57.5 St	BAHE
		6 0 CT	BAHE
26	Harris	75.0 Hy	CEMP
36	Mason	146 5 St	CEMP
62	Wyman	72 0 Hy	CEMP
70	Woodland	67 4 St	GEPA
		9 0 Hy	GEPA
77	Wiscasset	830.0 Nu	MAYA
86	Androscoggin	50.0 St	INPC
87	Penobscot	174 1 St	GRNP
		87.0 Hy	GRNP
88	Rumford	27 5 St	BOCA
89	Cumberland	21.7 St	WASD
		7.9 Hy	WASD

[1] Jointly owned by CEMP, NEEP, BAHE, BOEC and other utilities.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	MARYLAND		
5	Conowingo	474.5 Hy	SUEC
8	Dickerson	586.5 St	POEP
		16 2 CT	POEP
11	Gould Street	103.5 St	BAGE
13	Wagner	1042.6 St	BAGE
		16 0 CT	BAGE
16	Riverside	333.5 St	BAGE
		171.5 CT	BAGE
17	Smith	109 5 St	POEC
20	Sparrows Point	158.5 St	BESC
22	Vienna	229.6 St	DEPM
		18 6 CT	DEPM
23	Westport	194.0 St	BAGE
		121.5 CT	BAGE
25	Crane	399.8 St	BAGE
		16 0 CT	BAGE
26	Chalk Point	1386.7 St	POEP
		51.5 CT	POEP
		601 0 St*	POEP
27	Luke	44.0 St	WEPC
29	Morgantown	1251 0 St	POEP
		296 9 CT	POEP
30	Notch Cliff	144.0 CT	BAGE
31	Calvert Cliffs	1828.0 Nu	BAGE
32	Perryman	212.5 CT	BAGE
33	Philadephia Road	70.2 CT	BAGE
34	Easton	34.7 IC	EAUC
		12.5 IC*	EAUC
35	Brandon Shores	1370.0 St*	BAGE

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	MASSACHUSETTS		
5	Cabot	51.0 Hy	WEME
7	Cannon Street	83.0 St	NEBG
9	Cobble Mountain	33.0 Hy	SPRD[1]
17	Edgar	300.0 St	BOEC
		28.4 CT	BOEC
20	Fitchburg	22.4 St	FIGE
		25.6 CT	FIGE
24	Gloucester	26.5 IC	NEEP
28	Holyoke (6 plants)	2.9 Hy	HOLM
		24.8 St	HOLM
		10.0 CT	HOLM
29	Riverside	7.6 Hy	HOWP
		39.8 St	HOWP
34	Kendall	57.5 St	CAEL
		46.6 CT	CAEL
39	L Street - New Boston	747.7 St[9]	BOEC
		18.6 CT	BOEC
46	Mt Tom	136.0 St	HOWP
47	Mystic	1085.8 St	BOEC
		14.2 CT	BOEC
52	Peabody (2 plants)	11.2 IC	PEAB
		22.1 CT	PEAB
57	River Works	75.6 St	GEEC
58	Rowe	186.0 Nu	YAEC
59	Salem Harbor	809.5 St	NEEP
62	Somerset	325.0 St	MOEL
		42 4 CT	MOEL
65	West Water Street	51.3 St	TAUN
75	West Springfield	209.6 St	WEME
		18.6 CT	WEME
82	Brayton Point	1600.2 St	NEEP
		11.0 IC	NEEP
92	Canal	542.5 St	CACO
		530.0 St	CACO & MOEL
97	South Boston	120.0 St	MABT
98	Lincoln	35.0 St	MABT
		25.0 St 25Hz	MABT
99	Pilgrim	655.4 Nu	BOEC
		1180.0 Nu*	BOEC[6]
102	Framingham	42.6 CT	BOEC
105	Silver Lake	72.0 CT	WEME
108	West Medway	135.2 CT	BOEC
109	Cleary-Flood	27.2 ST	TAUN
		118.0 CC[8]	TAUN
110	Uxbridge	39.1 CT	NEEP
111	Northfield Mountain	846.0 Hy[3]	WEME[2]
112	Bear Swamp	600.0 Hy[3]	NEEP
113	Braintree (2 plants)	33.5 St	BRAI
		96.0 CC[5]	BRAI
		5.3 IC	BRAI
114	Stony Brook	390.0 CC*[7]	MMWE

[1] Leased to Western Massachusetts Electric Company.
[2] Jointly owned by COLP, HAEL, & WEME.
[3] Pumped Storage.
[5] 20 MW St plus 76 0 MW CT.
[6] Jointly owned by BOEC and other utilities.
[7] 270 0 MW St plus 120.0 MW CT.
[8] 93.5 MW St. plus 24.5 MW CT.
[9] Represents two adjacent plants.

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	MICHIGAN		
2	Advance	41 8 St	NOMC
5	Alpena	42 5 St	HUPD
10	Cobb, B C	510 5 St	COPR
29	Conners Creek	550 6 St	DEEC
		5 5 IC	DEEC
35	Karn D E	1135 0 St	COPR
		632 0 St*	COPR
36	Delray	391 0 St	DEEC
45	Fermi Enrico	158 0 Nu	DEEC
		64 0 CT	DEEC
		1215 0 Nu*	DEEC
57	Grand Haven	20 0 St	GRHA
		24 0 IC	GRHA
61	Hardy	30 0 Hy	COPR
71	De Young James	77 2 St	HOLL
72	Weadock John C	614 5 St	COPR
		20 6 CT	COPR
86	Marysville	208 0 St	DEEC
89	Midland	191 0 St	DOCC
93	Mistersky	175 0 St	DETR
		60 0 St*	DETR
		30 0 CT	DETR
94	Sault Ste Marie	41 3 Hy	EDSE
95	Eckert Otto E	386 0 St	LABW
96	Morrow Bryce E	186 0 St	COPR
		35 0 CT	COPR
98	Sixty Five	40 0 St	MISU
103	Wyandotte North	46 6 St	DEEC
106	Ottawa Street	81 5 St	LABW
113	Presque Isle	354 9 St	UPGC
		240 0 St*	UPGC
115	River Rouge	345 0 St	FOMC
116	River Rouge	933 2 St	DEEC
		11 0 IC	DEEC
121	St Clair	1905 0 St	DEEC
		18 6 CT	DEEC
		5 5 IC	DEEC
137	Bayside	35 0 St	TRAV
138	Trenton Channel	775 5 St	DEEC
144	Van Dyke	4 9 IC	WDEL
		23 5 CT	WDEL
151	White Pine	58 7 St	WHPC
		20 0 CT	WHPC
153	Whiting J R	325 0 St	COPR
		20 6 CT	COPR
156	Wyandotte	49 8 St	WYAN
		15 3 CT	WYAN
157	Campbell	650 0 St	COPR
		770 0 St*	COPR
		20 6 CT	COPR
163	Beacon	25 4 St	DEEC
166	Big Rock Point	75 0 Nu	COPR
169	Harbor Beach	121 0 St	DEEC
		4 0 IC	DEEC
170	Shiras	33 7 St	MARQ
		43 0 St*	MARQ
171	Palisades	811 7 Nu	COPR
172	Gaylord	90 6 CT	COPR
173	Pennsalt	37 0 St	DEEC
175	Northeast	129 9 CT	DEEC
176	Superior	64 0 CT	DEEC
178	Hancock	160 4 CT	DEEC
179	Monroe	3279 6 St	DEEC
		13 8 IC	DEEC
182	Thetford	237 0 CT	COPR
183	Midland	1381 3 Nu*	COPR
184	Ludington	1978 8 Hy	COPR[1]
185	Erickson	160 0 St	LABW
186	Cook D C	2200 0 Nu*	INME
187	Placid	27 5 IC	DEEC
188	Straits	25 0 CT	COPR
189	Johnson	22 0 CT	WDEL
		10 0 IC	WDEL
190	Tower	0 6 Hy	NOMC
		3 9 IC	NOMC
		21 3 CT	NOMC
191	Escanaba	58 3 St	MECP
192	Portage	47 6 CT	UPPP
193	Central	28 5 St	UNMI
194	Greenwood	815 0 St*	COPR

[1] Jointly owned by COPR and DEEC

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	MINNESOTA		
6	Syl Laskin	116 1 St	MIPL
7	Austin	59 6 St	AUMI
		6 0 CT	AUMI
11	Black Dog	486 7 St	NDSM
20	Boswell Clay	514 5 St	MIPL
		555 0 St*	MIPL
30	Elk River	45 0 St	UNPA
37	Fox Lake	104 6 St	INPD
		26 6 CT	INPD
46	High Bridge	396 8 St	NOSM
48	Hoot Lake	1 0 Hy	OTTP
		138 9 St	OTTP
51	International Fall	14 4 Hy	BOCL
		29 3 St	BOCL
76	Hibbard M L	122 6 St	MIPL
77	Minnesota Valley	46 0 St	NDSM
79	Moorhead	34 0 St	MOOR
		10 0 CT	MOOR
66	New Ulm	29 5 St	NEWU
		25 4 CT	NEWU
90	Owatonna	34 5 St	OWAT
100	Riverside	383 8 St	NDSM
105	Silver Bay	125 0 St	REMC
		9 0 IC	REMC
106	Silver Lake	98 4 St	ROCH
113	Taconite Harbor	225 0 St	ERMC
116	Thomson	22 5 Hy 25 Hz	MIPL
		46 6 Hy	MIPL
128	Wilmarth	25 0 St	NDSM
129	Willmar	30 4 St	WILM
146	West Faribault	48 5 CT	NOSM
147	Allen King	598 4 St	NOSM
149	Monticello	568 6 Nu	NDSM
150	Prairie Island	1186 2 Nu	NDSM
153	Chemolite	36 0 CT	NOSM
154	Key City	72 0 CT	NOSM
165	Granite City	72 0 CT	NDSM
156	Inver Hills	326 4 CT	NDSM
157	Plant No 1	36 2 St	VIRG
158	Sherburne Co	1440 0 St	NOSM
159	Cascade Creek	35 0 CT	ROCH
160	Montgomery	26 6 CT	INPD
161	Blue Lake	226 8 CT	NDSM
162	Hutchinson	15 9 CC	HUTC
		22 5 CT	HUTC
		21 3 IC	HUTC

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	MISSISSIPPI		
6	Delta	220 5 St	MIPO
7	Eaton	77 6 St	MIPR
9	Jack Watson	1173 5 St	MIPR
		41 9 CT	MIPR
12	Laurel	31 8 St	MACO
14	Natchez	66 0 St	MIPO
17	Rex Brown	383 2 St	MIPO
		10 0 CT	MIPO
18	Sweatt	95 0 St	MIPR
		41 9 CT	MIPR
19	Yazoo City	18 0 St	YACP
		12.5 CT	YACP
20	Clarksdale South	12 5 St	CLWL
		14 3 CT	CLWL
		25 6 CC	CLWL
21	Henderson	32 7 St	GRUT
		11 3 CT	GRUT
23	Baxter Wilson	1327 6 St	MIPO
24	Pascagoula	33 2 CT	MIPR
		32 2 CT	MIPR[1]
25	Moselle	177 0 St	SOMI
26	Jackson County	548 0 St*	MIPR
		548 0 St	MIPR
27	Andrus, Gerald	781 5 St	MIPO
28	Morrow	406 0 St*	SOMI
29	Grand Gulf Nuclear	1302 0 Nu*	MIPO

[1] Leased to Standard Oil

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	MISSOURI		
2	Ashley Street	20 0 St 25Hz	UNEC
		50 0 St	UNEC
13	Carthage	39.0 IC	CART
14	Chamois	59 0 St	CEEP
18	Columbia	102.8 St	COLM
		12.5 CT	COLM
19	Edmond Street	42.5 St	SAJL
23	Grand Avenue	10.0 St 25Hz	KACP
		116 8 St	KACP
25	Hannibal	34 0 St	HANN
28	Hawthorn	908.1 St	KACP
		2 0 IC	KACP
30	Jackson Square Station	36 0 CT	INDN
32	James River	253 0 St	SPRM
34	Hill, Jim	33.0 St	ARMP
39	Lake Road	150.5 St	SAJL
		85 0 CT	SAJL
45	Marshall	30 5 St	MARM
		15.3 CT	MARM
48	Meramec	923.0 St	UNEC
		62 0 CT	UNEC
57	Montrose	563.1 St	KACP
62	Northeast	133.0 St	KACP
		511 6 CT	KACP
64	Osage	176 2 Hy	UNEC
69	Pleasant Hill (Green, Ralph J.)	49 5 St	MIPU
85	Table Rock	200 0 Hy	USAR[1]
94	Blue Valley	115.0 St	INDN
		61 0 CT	INDN
95	Sibley	518 5 St	MIPU
96	Taum Sauk	408.0 Hy	UNEC
103	Sioux	1099 6 St	UNEC
104	Thomas Hill	470.0 St	ASEC
		670 0 St*	ASEC
105	Asbury	212 8 St	EMDE
106	Stockton	45 2 Hy	USAR[1]
107	Harry S. Truman	160.0 Hy*	USAR[1]
108	Cannon, C.	58 0 Hy*	USAR[1]
109	Viaduct	30 6 CT	MIUC
110	Labadie	2482 0 St	UNEC
111	New Madrid	650.0 St	NEMA[2]
		600 0 St	ASEC
112	Rush Island	1241.0 St	UNEC
113	Howard Bend	49 6 CT	UNEC
114	Station I	39 2 CT	INDN
115	Southwest	194 5 St	SPRM
116	Fulton	5.5 St	FULT
		19 6 CT	FULT
		14 6 IC	FULT
117	Jefferson City	62 0 CT	MILC
118	Station H	43.9 CT	INDN
119	Nevada	28 8 CT	MIPU
120	Greenwood	197.4 CT	MIPU
121	Kennett	31.9 IC	KENN
122	Iatan	725 9 St*	KACP[3]
123	KCI	30 0 CT	MIPU
124	Sikeston	235 0 St*	SIKE
125	Empire Energy Center	174 0 CT*	EMDE

[1] Power marketing under Southwestern Power Administration.
[2] Leased to Associated Electric Coop
[3] St. Joseph Light and Power Co owns 33%.

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	MONTANA		
5	Canyon Ferry	50 0 Hy	USBR
6	Cochrane	48 0 Hy	MOPO
8	Fort Peck	165 0 Hy	USAR
9	Bird, Frank	69.0 St	MOPO
10	Kerr	168 0 Hy	MOPO
14	Holter	38 4 Hy	MOPO
15	Hungry Horse	285 0 Hy	USBR
21	Morony	45 0 Hy	MOPO
23	Noxon Rapids	282.9 Hy	WAWP
		114 0 Hy	WAWP
24	Rainbow	35 6 Hy	MOPO
25	Ryan	48 0 Hy	MOPO
27	Thompson Falls	30 0 Hy	MOPO
28	Yellowtail	250 0 Hy	USBR
29	Lewis and Clark	50 1 St	MODU
31	Libby	420.0 Hy	USAR
32	J. E Corette	172 8 St	MOPO
34	Colstrip	716 0 St	MOPO[1]

[1] Jointly owned by MOPO & PSPL

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	NEBRASKA		
6	Bluffs	42 2 St	NEPP
13	Columbus	39.9 Hy	LORP[1]
21	Gavins Point	100 0 Hy	USAR
25	Hastings	50 5 St	HAST
		22.0 CT	HAST
30	Jones Street	83 5 St	OMPP
		130.0 CT	OMPP
33	Kramer	112 5 St	NEPP
34	Canaday	108.8 St	CENP[1]
35	Lincoln	31.7 St	LINK
		31 0 CT	LINK
42	North Omaha	644.7 St	OMPP
43	North Platte	26 1 Hy	NEPP
69	Burdick, C W.	93 5 St	GRIS
		14 8 CT	GRIS
71	Sheldon Station	228.6 St	NEPP
73	Fremont	134.8 St	FREM
79	Cooper	801 0 Nu	NEPP
80	Ft. Calhoun	481.5 Nu	OMPP
		5 1 IC	OMPP
81	Sarpy	110 8 CT	OMPP
82	Hebron	38 1 CT	NEPP
83	McCook	36 7 CT	NEPP
84	Hallam	38.1 CT	NEPP
85	Gentleman, Gerald	650 0 St*	NEPP
86	Nebraska City	575.0 St*	OMPP
87	Rokeby	49 8 CT	LINK

[1] Leased to Nebraska Public Power District

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Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEVADA		
1	Clark	190.3 St	NEPC
		72.0 CT	NEPC
5	Hoover—NV	672.5 Hy	USBR[1]
5	Hoover—AZ	667 5 Hy	USBR[1]
16	Tracy	25 0 CT	SIPP
		242 6 St	SIPP
17	Westside	29 3 IC	NEPC
18	Sunrise	81 6 St	NEPC
		72 0 CT	NEPC
20	Reid Gardner	339.0 St	NEPC
22	Ft. Churchill	210.0 St	SIPP
24	Mohave	1636.2 St	SOCE[2]
25	McGill	45.0 St	KECC

[1] State of Nevada, Division of Colorado River Resources, formerly Colorado River Commission of Nevada, acquired Units N-8, A-9, Arizona Power Authority acquired Units A-3, A-4.
[2] Joint ownership with LOAN, NEPC, & SARV.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEW HAMPSHIRE		
3	Merrimack	459.2 St	PSNH
		37.2 CT	PSNH
6	Comerford	140.4 Hy	NEEP
28	Berlin	32.5 Hy	BRCO
		17.0 St	BRCO
		3.3 IC	BRCO
30	Moore	140.4 Hy	NEEP
32	Schiller	178.8 St	PSNH
		21.3 CT	PSNH
33	Newington	414.0 St	PSNH
34	Seabrook	2300.0 Nu*	PSNH[1]

[1] Jointly owned by PSNH, UNIC, COLP, NEEP, and others.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEW JERSEY		
1	Bergen	650 4 St	PSEG
		61 8 CT	PSEG
2	Burlington	125 6 CC[5]	PSEG
		442 5 St	PSEG
		437 1 CT	PSEG
3	Deepwater	308 3 St	ATCE[3]
		18 6 CT	ATCE[3]
4	Werner	60.0 St	JECP
		212.4 CT	JECP
5	Essex	117 0 St	PSEG
		585 3 CT	PSEG
6	Gilbert	126.1 St	JECP
		95 2 CT	JECP
		335.2 CC[6]	JECP
8	Kearney	294.1 St	PSEG
		517 4 CT	PSEG
9	Linden	612 9 St	PSEG
		320 1 CT	PSEG
12	Mercer	652.8 St	PSEG[6]
		115 2 CT	PSEG[6]
15	Missouri Avenue	55.8 CT	ATCE
19	Sayreville	343 8 St	JECP
		212 4 CT	JECP

NEW JERSEY—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEW JERSEY—Continued		
20	Sewaren	820 0 St	PSEG
		115 2 CT	PSEG
22	Vineland (2 plants)	76 5 St	VINE
		27 0 CT	VINE
25	England	475 6 St	ATCE
26	Oyster Creek	550.0 Nu	JECP & PSEG
29	Hudson	1114 5 St	PSEG
		115 2 CT	PSEG
30	Middle	79 8 CT	ATCE
31	Paulsboro	32 7 St	MOOC
32	Bayonne	42 5 CT	PSEG
33	Edison	502 2 CT	PSEG
34	Glen Gardner	156 8 CT	JECP
35	Salem	1090.0 Nu	PSEG[2]
		1115.0 Nu*	PSEG[2]
		41.9 CT	PSEG[2]
36	Cedar	63 1 CT	ATCE
37	Carl's Corner	83 7 CT	ATCE
38	Mickleton	71 2 CT	ATCE
39	Forked River	1228 0 Nu*	JECP[4] & ATCE

[1] Pumped Storage
[2] Jointly owned by PSEG, PHEC, DEPL, & ATCE
[3] Operated by Deepwater Operating Co
[4] Jointly owned by JECP, PEEC, & MEEC.
[5] 41 9 MW St. plus 83.7 MW CT
[6] 130 0 MW St plus 205 2 MW CT

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEW MEXICO		
2	Algodones	51 8 St	PLEG
5	Carlsbad No. 2	44 3 St	SOPS
8	Cunningham	265 4 St	SOPS
13	Lordsburg	41 5 St	COPS
		13 0 CT	COPS
14	North Lovington	20 0 IC	LECE
		59 6 St	LECE
15	Person	125 0 St	PSNM
16	Prager	25 0 St	PSNM
18	Rio Grande	401 5 St	ELPE
19	Roswell	24 2 St	SOPS
		11 5 CT	SOPS
24	Farmington	28 5 St	FATN
25	Reeves	175 0 St	PSNM
26	Four Corners	633 6 St[1]	ARPS[3]
		1636 2 St[2]	ARPS[3]
27	Maddox	113 6 St	NEME
		80 6 CT	NEME
29	San Juan	676 1 St[4]	PSNM[6]
		1068 0 St*[5]	PSNM[6]

[1] Units 1, 2 and 3
[2] Units 4 and 5
[3] Jointly owned with SOCE, SARV, ELPE, PSNM and TUGE
[4] Units 1 and 2
[5] Units 3 and 4.
[6] Jointly owned with TUGE

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Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NEW YORK		
2	Albany	400 0 St	NIMP
		0 7 IC	NIMP
		155.6 CT	NIMP
5	Arthur Kill	911.7 St	COEN
		16 3 CT	COEN
6	Astoria	1550 6 St	COEN
		826 0 St	POAS
		744 5 CT	COEN
8	Moses, Robert– St Lawrence	912 0 Hy	POAS
13	Bennetts Bridge	26 8 Hy	NIMP
21	Greenidge	170 0 St	NEYE
24	Huntley	828 0 St	NIMP
		0 7 IC	NIMP
26	Colton	30.0 Hy	NIMP
29	Danskammer	531 9 St	CEHG
36	Dunkirk	628.0 St	NIMP
		0 7 IC	NIMP
40	East River	512 5 St	COEN
42	Barrett	375.0 St	LOIL
		311.4 CT	LOIL
48	Far Rockaway	113 6 St	LOIL
57	Freeport (2 plants)	33 5 IC	FREP
		20 9 CT	FREP
62	Glenwood	377 3 St	LOIL
		126 8 CT	LOIL
63	Goudey	145 8 St	NEYE
74	Hickling	74 5 St	NEYE
82	Hudson Avenue	600 0 St	COEN
		100 0 St 25Hz	COEN
		84 6 CT	COEN
84	Indian Point	1288 0 Nu	COEN
		1125 0 Nu	POAS
		61 4 CT	COEN
86	Jennison	67 5 St	NEYE
91	Kodak Park	113 7 St	EAKC
		0.5 Hy	EAKC
97	Lovett	495 1 St	ORRU
105	Milliken	270.0 St	NEYE
		5 5 IC	NEYE
111	Neversink	25 0 Hy	CEHG
114	Northport	1161 3 St	LOIL
		387 0 St*	LOIL
		16.0 CT	LOIL
121	Oswego	1277.9 St	NIMP
		850 0 St*	NIMP & ROGE
		0 7 IC	NIMP
129	Port Jefferson	467 0 St	LOIL
		16 0 CT	LOIL
139	Rockville Centre	31 4 IC	ROCK
141	Schenectady	27 5 St 40Hz	GEEC
143	School Street	38 8 Hy	NIMP
148	Sherman Island	28.8 Hy	NIMP
154	Spier Falls	44.4 Hy	NIMP
157	Station No. 3	196 2 St	ROGE
		19 0 CT	ROGE
158	Station No 5	38 3 Hy	ROGE
159	Station No 7 (Russell)	252 6 St	ROGE
161	Carlson	82 5 St	JAME
162	Stewarts Bridge	30.0 Hy	NIMP

NEW YORK – Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	NEW YORK –Continued		
180	Waterside	70 0 St 25Hz	COEN
		532 3 St	COEN
		14 0 CT	COEN
184	Kent Avenue	28 0 CT	COEN
185	59th Street	184 5 St 25Hz	COEN
		34 2 CT	COEN
186	74th Street	65 0 St 25Hz	COEN
		144.0 St	COEN
		37 2 CT	COEN
187	Moses, Robt – Niagara	1950 0 Hy	POAS
188	Lewiston Pump	240 0 Hy[2]	POAS
189	Ravenswood	1827 7 St	COEN
		481 8 CT	COEN
191	East Hampton	6 0 IC	LOIL
		21 3 CT	LOIL
198	Lackawanna (2 plants)	47 5 St 25Hz	BESC
199	Nine Mile Point	641 7 Nu	NIMP
		1166 0 Nu*	NIMP[3]
		5 0 IC	NIMP
200	Syracuse	54 5 St	ALCC
202	West Babylon	108 7 CT	LOIL
203	Station No 13	517 1 Nu	ROGE
205	Rotterdam	165 6 CT	NIMP
207	Blenheim–Gilboa	1000 0 Hy[2]	POAS
208	Fitzpatrick	883 0 Nu	POAS
210	Roseton	1242 0 St	CEHG[1]
211	Shoreham	849 0 Nu*	LOIL
		52 9 CT	LOIL
212	Hillburn	39 5 CT	ORRU
213	Bowline Point	1 242 0 St	ORRU & COEN
215	Gowanus	688 0 CT	COEN
216	Hudson	27 5 St	INPC
		11 8 Hy	INPC
217	Narrows	393 1 CT	COEN
218	Holbrook	567 0 CT	LOIL
219	Shoemaker	39 5 CT	ORRU
220	Ticonderoga	30 0 St	INPC

[1] Jointly owned by CEHG, NIMP & COEN
[2] Pumped Storage
[3] Jointly owned by NIMP, NEYE LOIL, ROGE & CEHG.

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	NORTH DAKOTA		
11	Garrison	400.0 Hy	USAR
15	Heskett	100 1 St	MODU
21	Neal, Wm. J	34.5 St	CEPE
29	Olds, Leland	240.0 St	BAEP
		438 0 St*	BAEP
33	Stanton	172.0 St	UNPA
34	Milton R. Young	686.5 St	MIPI
35	Jamestown	28.8 CT	OTTP
36	Coal Creek	1100.0 St*[1]	UNPA

[1] Jointly owned by COLC.

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LIST OF POWER PLANTS IN THE UNITED STATES

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Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	NORTH CAROLINA		
6	Buck	440 0 St	DUPC
		93 0 CT	DUPC
10	Canton	51 0 St	CHPA
11	Cape Fear	421 0 St	CAPO
		72 0 CT	CAPO
15	Cheoah	110 0 Hy	TAPI
17	Cliffside	780 9 St	DUPC
20	Dan River	290.0 St	DUPC
		85 0 CT	DUPC
		14 0 IC	DUPC
25	Enka	23 8 St	AMEC
		2 6 St 13GHz	AMEC
28	Fontana	225 0 Hy	TVA
30	Allen, G. G	1155 0 St	DUPC
31	Gaston	177 9 Hy	VIEP
32	Lee, H F	402 5 St	CAPO
		106 2 CT	CAPO
34	High Rock	33 0 Hy	YADI
36	Hiwassee	117 1 Hy	TVA
41	Sutton, L. V	671 6 St	CAPO
		447 0 St*	CAPO
		91 3 CT	CAPO
46	Weatherspoon	165 5 St	CAPO
		176 7 CT	CAPO
52	Mtn Island	60 0 Hy	DUPC
53	Nantahala	43 2 Hy	NAPL
55	Oxford	36 0 Hy	DUPC
58	Rhodhiss	25 5 Hy	DUPC
59	Riverbend	631 0 St	DUPC
		120 0 CT	DUPC
60	Roanoke Rapids	100 1 Hy	VIEP
64	Santeetlah	45 0 Hy	TAPI
68	Tillery	84 0 Hy	CAPO
72	Walters	108 0 Hy	CAPO
76	Yadkin Falls	29 5 Hy	YADI
77	Yadin Narrows	96 5 Hy	YADI
78	Cowans Ford	350 0 Hy	DUPC
79	Tuckertown	42 0 Hy	YADI
80	Asheville	413 6 St	CAPO
81	Marshall	2000 0 St	DUPC
82	Roxboro	1813 1 St	CAPO
		745 0 St*	CAPO
		16 3 CT	CAPO
84	Belews Creek	2160 0 St	DUPC
85	Brunswick	867 0 Nu	CAPO
		867 0 Nu*	CAPO
86	Kitty Hawk	47 6 CT	VIEP
87	McGuire	2440.0 Nu*	DUPC
88	Blewett	70 0 CT	CAPO
		24 6 Hy	CAPO
89	Harris, S	3804 0 Nu*	CAPO
90	Mayo	1472 0 St*	CAPO
91	Perkins	3840 0 Nu*	DUPC
	OHIO		
1	Acme	307 5 St	TOEC
2	Firestone No 1	57 5 St	FITR
4	Akron	64 6 St	GOTR
7	Ashtabula	648 0 St	CLEI
9	Avon Lake	1275 0 St	CLEI
		32 1 CT	CLEI
11	Barberton	83 8 St	PIPG
12	Bay Shore	639 6 St	TOEC
		16 0 CT	TOEC

OHIO—Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	OHIO—Continued		
13	Beckjord	760 5 St	CIGE
		468 5 St	CIGE[1]
		221 6 CT	CIGE
17	Campbell	48 5 St	VOST
22	Columbus	46 5 CC[6]	COLU
24	Conesville	877 5 St	COSO
		841 5 St	COSO[1]
		13 8 IC	COSO
		440 0 St*	COSO
27	Dover	33 0 St	DOVE
		2 7 IC	DOVE
29	Eastlake	677 0 St	CLEI
		680 4 St	CLEI & DULC
		32 1 CT	CLEI
31	Edgewater	282 8 St	OHEC
		58 3 CT	OHEC & PEPC
34	Tait Frank M	444 1 St	DAPO
		11 0 IC	DAPO
37	Gorge	80 5 St	OHEC
38	Hamilton	127 5 St	HAMI
		27 6 CT	HAMI
		1 5 Hy	HAMI
42	Kyger Creek	1125 0 St	OHVE
43	Lake Road	160 0 St	CLEV
44	Lake Shore	514 0 St	CLEI
		4 0 IC	CLEI
46	Lorain	28 8 St 25Hz	UNSS
48	Mad River	63 0 St	OHEC
		54 0 CT	OHEC & PEPC
54	Miami Fort	950 2 St	CIGE
		557 0 St*	CIGE & DAPO
		171 5 CT	CIGE
57	Muskingum River	1529 8 St	OHPC
60	Niles	265 6 St	OHEC
		27 0 CT	OHEC & PEPC
61	Norwalk	31 0 St	OHEC
		1 0 IC	OHEC
63	Hutchings O H	414 0 St	DAPO
		32 6 CT	DAPO
65	North Vine Street	102 5 St	ORRV
66	Painesville	40 3 St	PAIN
		25 0 St*	PAIN
69	Philo	295 0 St	OHPC
70	Picway	170 8 St	COSO
		18 6 CT	COSO
71	Piqua	42 9 St	PIQU
		20 1 CT	PIQU
73	Poston	232 0 St	COSO
		907 0 St*	COSO
		13 8 IC	COSO
75	Burger	531 0 St	OHEC
		7 5 IC	OHEC & PEPC
78	Rossford	27 6 St	LIOF
83	Shelby	37 5 St	SHBY
		3 0 IC	SHBY
84	Sammis	1775 7 St	OHEC
		680 0 St	OHEC[3]
		12 5 IC	OHEC & PEPC
87	Tidd	226 3 St	OHPC
90	Toronto	173 0 St	OHEC
93	Walnut	232 7 CT	COSO
100	Woodcock	37 5 St	OHPC
102	Youngstown	27 5 St	RESC
109	Marietta	160 8 St	UNCA
112	Chillicothe	67 1 St	MECP
113	Cardinal	615 2 St	OHPC[2]
		615 2 St	BUPI[2]
		615 0 St*	BUPI[2]
114	Dick s Creek	193 0 CT	CIGE
115	Richland	45 0 CT	TOEC
116	Stuart	2440 8 St	DAPO[1]
		11 0 IC	DAPO[1]
119	Youngstown	45 0 St	UNSS
121	Cleveland	42 5 St	RESC
122	West 41 St	32 4 CT	CLEV
123	Yankee St	126 0 CT	DAPO
124	Celina	25 0 St	CELI
126	Zimmer	878 0 Nu*	CIGE & CLEI
128	Gavin	2600 0 St	OHEL & PEPC
130	Perry	2528 0 Nu*	CLEI[4]

[1] Unit jointly owned by CIGE, DAPO & COSO
[2] Operated by Cardinal Operating Company
[3] Jointly owned by OHEC DULC & PEPC
[4] Jointly owned by CLEI DULC PEPC TOEC, & OHEC
[5] 104 0 MW St plus 139 3 MW CT
[6] 32 0 MW St plus 14 5 MW CT

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	OKLAHOMA		
3	Anadarko	84 5 St	WEFA
		315 0 CC*	WEFA
4	Arbuckle	73 5 St	OKGE
		1 1 IC	OKGE
5	Belle Isle	55 0 St	OKGE
		8 0 CT	OKGE
13	Chouteau	56 3 St	GRRD
20	Fort Gibson	45 0 Hy	USAR[1]
23	Horseshoe Lake	916 2 St	OKGE
		27 2 CT	OKGE
		2 0 IC	OKGE
32	Mustang	509 3 St	OKGE
		83 7 CT	OKGE
		1 0 IC	OKGE
36	Osage	40 0 St	OKGE
39	Pensacola	86 4 Hy	GRRD
41	Ponca City	30 3 IC	PONC
		19 0 St	PONC
		43 2 St*	PONC
43	Muskogee	195 9 St	OKGE
		0 3 IC	OKGE
		0 5 IC*	OKGE
		1144 8 St*	OKGE
46	Southwestern	482 7 St	PSOK
		6 0 IC	PSOK
49	Tenkiller Ferry	34 0 Hy	USAR[1]
51	Tulsa	468 0 St	PSOK
		8 3 IC	PSOK
54	Weleetka	58 0 St	PSOK
		201 2 CT	PSOK
59	Eufaula	90 0 Hy	USAR[1]
60	Northeastern	642 5 St	PSOK
		2 8 IC	PSOK
		900 0 St*	PSOK
64	Markham Ferry Kerr	108 0 Hy	GRRD
66	Mooreland	327 0 St	WEFA
67	Broken Bow	100 0 Hy	USAR[1]
68	Keystone	70 0 Hy	USAR[1]
69	Robert S Kerr	110 0 Hy	USAR[1]
71	Enid	60 0 CT	OKGE
72	Salina	259 2 Hy	GRRD
73	Webbers Falls	60 0 Hy	USAR[1]
74	Seminole	1701 0 St	OKGE
		23 9 CT	OKGE
75	Riverside	945 0 St	PSOK
		3 0 IC	PSOK
76	Comanche	290 0 CC	PSOK
77	Sooner	1137 6 St*	OKGE

[1] Power marketing under Southwestern Power Administration

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	OREGON		
5	Boyle, J C	80 0 Hy	PAPL
7	Bonneville	518 4 Hy	USAR
		544 0 Hy*	USAR[1]
9	Clearwater No 2	26 0 Hy	PAPL
13	Cougar	25 0 Hy	USAR
15	Detroit	100.0 Hy	USAR
19	Eugene (Willamette)	25 0 St	EUGE
21	Faraday	34.5 Hy	POGE
30	Hills Creek	30 0 Hy	USAR
38	Lemolo No 1	29 0 Hy	PAPL
39	Lemolo No 2	33 0 Hy	PAPL
40	Lincoln	35 5 St	PAPL
41	Lookout Point	120 0 Hy	USAR
43	McNary	980 0 Hy	USAR
49	North Fork	38.4 Hy	POGE
52	Oxbow	190 0 Hy	IDPC
53	Pelton	108.0 Hy	POGE
59	Prospect No 2	32 0 Hy	PAPL
70	Springfield	25 0 St	WETC
76	Oak Grove	51 0 Hy	POGE
81	Toketee	42.5 Hy	PAPL
94	John Day	2160.0 Hy	USAR
96	Carmen	80 0 Hy	EUGE
99	Round Butte	247 1 Hy	POGE
100	Hells Canyon	391 5 Hy	IDPC
101	Green Peter	80.0 Hy	USAR
102	Trojan	1216 0 Nu	POGE
103	Lost Creek	49 0 Hy*	USAR
104	Harborton	226 8 CT	POGE
105	Bethel	113 4 CT	POGE
106	Beaver	409 8 CT[2]	POGE
		176.0 St*[2]	POGE
107	Weyco Energy Center	51 2 St[4]	EUGE
108	Roseburg	37 5 St	ROLC
110	Boardman	530 0 St*[3]	POGE

[1] Bonneville second P H.
[2] Will be operated as combined cycle plant
[3] Jointly owned with IDPC and others
[4] Cogeneration with Weyerhaeuser Corp

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	PENNSYLVANIA		
1	Armstrong	326.4 St	WEPP
4	Barbadoes	132.0 St	PHEC
		66 3 CT	PHEC
		2.8 IC	PHEC
5	Bethlehem	12.5 St	BESC
		14.0 St 25Hz	BESC
		17.5 IC 25Hz	BESC
11	Chester	130.0 St	PHEC
		55.8 CT	PHEC
		2.8 IC	PHEC
15	Cromby	417.5 St	PHEC

PENNSYLVANIA—Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	PENNSYLVANIA —Continued		
17	Delaware	2.8 IC	PHEC
		312.5 St	PHEC
		77.1 CT	PHEC
		2 8 IC	PHEC
29	Eddystone	1471 2 St	PHEC
		79 7 CT	PHEC
21	Elrama	510 3 St	DULC
26	Phillips	411.2 St	DULC
27	Front Street	118.8 St	PEEC
35	Holtwood	75 0 St	PEPL
36	Holtwood	107 2 Hy	PEPL
38	Hunlock	50.0 St	UNGI
42	Johnstown	74 5 St 25Hz	BESC
44	Martins Creek	2013.5 St	PEPL
		94.3 CT	PEPL
		5.5 IC	PEPL
45	Milesburg	46 0 St	WEPP
46	Mitchell	448.7 St	WEPP
51	New Castle	425 1 St	PEPC
		5.5 IC	PEPC & OHEC
58	Piney	28.8 Hy	PEEC
60	Pittsburg Works	70 0 St 25Hz	JOLS
62	Portland	426 7 St	MEEC
		37.6 CT	MEEC
65	Richmond	354.8 St	PHEC
		729.7 CT	PHEC
		2.8 IC	PHEC
67	Safe Harbor	160 6 Hy	SAHW
		70.0 Hy 25Hz	SAHW
69	Schuylkill	275 4 St	PHEC
		2 8 IC	PHEC
		39 9 CT	PHEC
70	Seward	280.2 St	PEEC
72	Shawville	625.0 St	PEEC
		6.0 IC	PEEC
73	Shippingport	100.0 Nu	DULC
75	Southwark	345.0 St	PHEC
		74.4 CT	PHEC
		2.8 IC	PHEC
76	Springdale	215.4 St	WEPP
82	Suburban	29.3 CT	PEPL
83	Sunbury	409.8 St	PEPL
		47.2 CT	PEPL
		5.5 IC	PEPL
85	Titus	225 0 St	MEEC
		35 6 CT	MEEC
86	Wallenpaupack	40 0 Hy	PEPL
87	Warren	84 6 St	PEEC
		53 1 CT	PEEC
90	Williamsburg	25.0 St	PEEC
92	Brunner Island	1558.7 St	PEPL
		8 3 IC	PEPL
94	Peach Bottom	2304.0 Nu	PHEC[6]
96	Seneca	422.1 Hy[4]	PEEC & CLEI
100	Josephtown	100 0 St	SAJC
103	Keystone	1872.0 St	PEEC[1]
		11 0 IC	PEEC[1]
104	Muddy Run	800 0 Hy[4]	PHEC
105	Harwood	32 0 CT	PEPL
106	Allentown	64.0 Ct	PEPL
107	Harrisburg	64.0 CT	PEPL

PENNSYLVANIA—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	PENNSYLVANIA — Continued		
108	Williamsport	32.0 CT	PEPL
110	Fishbach	37.2 CT	PEPL
111	West Shore	37.2 CT	PEPL
113	Homer City	1320.0 St	PEEC & NEYE
		693.0 St*	PEEC & NEYE
		5.3 IC	PEEC & NEYE
114	Conemaugh	1872.0 St	PEEC[3]
		11 0 IC	PEEC[3]
115	Cheswick	565 3 St	DULC
116	Hatfields Ferry	1728.0 St	WEPP[5]
117	Jenkins	32 0 CT	PEPL
118	Montour	1624.5 St	PEPL
119	Moser	63 8 CT	PHEC
120	Falls	63 8 CT	PHEC
121	Three Mile Island	871 0 Nu	MEEC[8]
		927.0 Nu*	MEEC[8]
122	Plymouth Meeting	6 0 IC	PHEC
		85.9 CT	PHEC
123	Aliquippa	47.0 St	JOLS
124	Girard Point	30 0 St	GUOC
125	Kobuta	35.0 St	ARPO
126	Fairless	60.0 St	UNSS
127	Clairton	40 0 St	UNSS
		49 0 IC	UNSS
128	Edgar Thomson	65 0 St	UNSS
129	Homestead	67.3 St	UNSS
130	Hunterstown	58.8 CT	MEEC
131	Mountain	53.2 CT	MEEC
132	Erie	39.5 St	HAPA[11]
133	Wayne	53.1 CT	PEEC
134	Tolna	53 2 CT	MEEC
135	Beaver Valley	923 4 Nu	DULC[9]
		923 0 Nu*	DULC[13]
136	Mansfield	913 7 St	PEPC[10]
		1670 0 St*	PEPC[7]
137	Brunot Island	339 0 CC[12]	DULC
		75 0 CT	DULC
138	Croydon	546 4 CT	PHEC
139	Susquehanna	2100.0 Nu*	PEPL[2]
140	Limerick	2196.0 Nu*	PHEC

[1] Jointly owned by ATCE, BAGE, DEPL, JECP, PEPL, PHEC, & PSEG, and operated by PEEC
[2] Jointly owned by PEPL & Allegheny Electric Cooperative
[3] Jointly owned by PEPL, PHEC, BAGE, POEP, PSEG, ATCE, DEPL, UNGI, & MEEC, and operated by PEEC
[4] Pumped Storage
[5] Jointly owned by WEPP, MOPC, & POEC
[6] Jointly owned by ATCE, DEPL, PSEG, & PHEC
[7] Jointly owned by PEPC, DULC, CLEI, OHEC & TOEC
[8] Jointly owned by MEEC, JECP & PEEC
[9] Jointly owned by DULC, OHEC & PEPC.
[10] Jointly owned by PEPC, OHEC, CLEI, & DULC
[11] Owned by Endbehr Corp , a subsidiary of HAPA
[12] 144 0 MW St. plus 195 0 MW CT.
[13] Unit jointly owned by DULC, CLEI, OHEC & TOEC.

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Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	RHODE ISLAND		
4	Manchester Street	132.0 St	NAEC
13	South Street	110.9 St	NAEC
		5.5 IC	NAEC
	SOUTH CAROLINA		
6	Wylie	60.0 Hy	DUPC
7	Cedar Creek	45.0 Hy	DUPC
8	Charleston	48.3 St	WEPC
12	Clark Hill	280.0 Hy	USAR[1]
15	Dearborn	45.0 Hy	DUPC
16	Fishing Creek	36.7 Hy	DUPC
20	Hagood	97.8 St	SOCG
21	Hartsville	0.3 Hy	SOPC
		26.2 St	SOPC
23	Lee	345.0 St	DUPC
		90.0 CT	DUPC
26	Mathews No. 1	25.0 St	GRMI
33	Parr	72.5 St	SOCG
		82.6 CT	SOCG
36	Jefferies Steam	445.6 St	SOCA
39	Rocky Creek	28.0 Hy	DUPC
41	McMeekin, S. C.	293.8 St	SOCG
42	Saluda	197.5 Hy	SDCG
44	Jefferies Hydro	132.6 Hy	SOCA
48	Tiger	30.0 St[3]	DUPC
49	Urquhart	250.0 St	SOCG
		78.5 CT	SOCG[2]
51	Wateree	56.0 Hy	DUPC
53	Robinson, H B	206.6 St	CAPO
		16.3 CT	CAPO
		768.7 Nu	CAPO
54	Conway (Grainger)	163.2 St	SOCA
56	Canadys	489.6 St	SOCG
		16.5 CT	SDCG
57	Burton	34.9 CT	SOCG
60	Oconee	2655.0 Nu	DUPC
61	Keowee	140.0 Hy	DUPC
62	Jocassee	610.0 Hy	DUPC
63	Wateree	771.8 St	SOCG
64	Coit	43.0 CT	SOCG
65	Buzzard Roost	196.0 CT	DUPC
66	Williams	60.0 CT	SOCG
		632.7 St	SOCG
		500.0 St*	SOCG
67	Summer	1854.0 Nu*	SOCG
68	Fairfield	512.0 Hy*	SDCG
69	Winyah	315.0 St	SOCA
		945.0 St*	SOCA
70	Greenwood	36.6 St[4]	DUPC
71	Myrtle Beach	111.3 CT	SOCA
72	Hilton Head	53.3 CT	SOCA
73	Catawba	2410.0 Nu*	DUPC
74	Darlington	728.8 CT	CAPO
75	Cherokee	3840.0 Nu*	DUPC
76	Bad Creek	750.0 Hy*	DUPC

[1] Power marketing under Southeastern Power Administration
[2] Jointly owned by SOCG and DUPC
[3] Retired February 1, 1976
[4] Retired January 1, 1975

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	SOUTH DAKOTA		
13	Fort Randall	320.0 Hy	USAR
16	Kirk	15.0 St	BLHP
		16.5 St	RUEP[1]
18	Lawrence	48.0 St	NOSM
24	Oahe	595.0 Hy	USAR
46	Pathfinder	75.0 St	NOSM
47	French, Ben	22.0 St	BLHP
		10.0 IC	BLHP
		44.0 CT*	BLHP
50	Big Bend	468.0 Hy	USAR
51	Big Stone	455.7 St	OTTP[2]
52	Clay County	120.0 CT*	BAEP

[1] 16.5 MW leased to Black Hills Power & Light Co.
[2] Plant jointly owned by OTTP, MODU, & NOPS.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	TENNESSEE		
1	Appalachia	79.0 Hy	TVA
2	Boone Dam	75.0 Hy	TVA
3	Calderwood	121.5 Hy	TAPI
4	Calhoun	45.0 St	BOSP
5	Cheatham	36.0 Hy	USAR
6	Center Hill	135.0 Hy	USAR
7	Cherokee	129.0 Hy	TVA
8	Chicamauga	108.0 Hy	TVA
9	Chilhowee	50.0 Hy	TAPI
11	Dale Hollow	54.0 Hy	USAR
12	Douglas	115.0 Hy	TVA
14	Fort Loudoun	135.0 Hy	TVA
15	Fort P Henry	36.0 Hy	TVA
17	Gallatin	1255.2 St	TVA
		325.0 CT*	TVA
18	Great Falls	31.9 Hy	TVA
21	Sevier, John	823.3 St	TVA
22	Johnsonville	1485.2 St	TVA
		1088.0 CT	TVA
23	Kingston	1700.0 St	TVA
24	Allen, Thomas H	990.0 St	MELG[1]
		620.8 CT	TVA
27	Norris Dam	100.8 Hy	TVA
30	Ocoee No 3	29.0 Hy	TVA
31	Old Hickory	100.0 Hy	USAR
33	Pickwick Landing	220.0 Hy	TVA
34	South Holston	35.0 Hy	TVA
35	Watts Bar	153.0 Hy	TVA
36	Watts Bar	240.0 St	TVA
39	Watauga	50.0 Hy	TVA
40	Melton Hill	72.0 Hy	TVA
41	Bull Run	950.0 St	TVA
42	Nickajack	97.2 Hy	TVA
43	Cordell Hull	100.0 Hy	USAR
44	J Percy Priest	28.0 Hy	USAR

TENNESSEE—Continued

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LIST OF POWER PLANTS IN THE UNITED STATES

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	TENNESSEE—Continued		
45	Tims Ford	45 0 Hy	TVA
46	Cumberland	2600 0 St	TVA
47	Sequoyah	2441 2 Nu*	TVA
48	Raccoon Mt	1530 0 Hy*	TVA
49	Watts Bar	2539 8 Nu*	TVA
50	Hartsville	5148 0 Nu*	TVA

[1] Leased to TVA

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	TEXAS		
2	Abilene	26 3 St	WETU
5	Seaholm	125 0 St	AUST
7	Baytown	60 0 St	EXCO
		34 4 CT	EXCO
8	Beaumont (2 plants)	135 0 St	MOOC
14	Brownsville (Si Ray)	53 0 St	BROV
		66 6 CT	BROV
16	Bryan	125 2 St	BRYN
		.24 5 CT	BRYN
17	Buchanan	33 8 Hy	LOCR
25	Collin	156 3 St	TEPL
28	Concho	52.5 St	WETU
32	Dallas	223 8 St	DAPL
33	Lone Star	32.9 St	LOSS
34	Deepwater	334 9 St	HOLP
36	Denison	70 0 Hy	USAR[2]
38	Denton	189 3 St	DENT
39	Denver City	80 0 St	SOPS
44	Eagle Mountain	706 2 St	TEES
46	East	61 0 St	SOPS
47	Newman, C E	96 5 St	GARL
49	Falcon Dam	31 5 Hy	INBW[3]
53	Freeport (4 plants)	899 0 St	DOCC
54	Gable Street	53 0 St	HOLP
60	Granite Shoals	45 0 Hy	LOCR
61	Greens Bayou	821 4 St	HOLP
		432.0 CT	HOLP
62	Greenville (2 plants)	17.9 IC	GRUD
		43 8 St	GRUD
		42 0 St*	GRUD
66	Handley	978 4 St	TEES
		455 0 St*	TEES
69	Clarke, Hiram O	210 0 St	HOLP
		96.0 CT	HOLP
70	Houston	70 0 St	PETE
74	Bates, J L	188.7 St	CEPL
77	Lee Knox	537 0 St	SOEP
78	Lake Creek	315 6 St	TEPL
		6 0 IC	TEPL
80	Laredo	187 0 St	CEPL
82	Leon Creek	263 6 St	SAAN
85	Hill, Lon C.	574 2 St	CEPL
86	Lone Star	50 0 St	SOEP
		49 0 CT	SOEP
88	Lubbock	80 5 St	LUBB
		14 2 IC	LUBB
89	Lufkin	78 5 St	SOPM

TEXAS—Continued

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	TEXAS—Continued		
90	Mansfield	67 5 Hy	LOCR
91	Marble Falls	30.0 Hy	LOCR
96	Mission Road	163.6 St	SAAN
97	Moore County	68 2 St	SOPS
98	Morgan Creek	829.6 St	TEES
		2.3 IC	TEES
100	Mountain Creek	989 7 St	DAPL
101	Neches	452 3 St	GUSU
102	Newman	265 8 St	ELPE
		290 0 CC	ELPE
104	Wharton, T H.	548 9 St	HOLP
		947.5 CT	HOLP
105	North Lake	708 6 St	DAPL
106	North Main	116 3 St	TEES
107	Nueces Bay	595 5 St	CEPL
109	Paint Creek	241 6 St	WETU
111	Parkdale	340 6 St	DAPL
112	Pauline	44 5 St	WETU
114	Permian Basin	700 5 St	TEES
		1 1 IC	TEES
117	Plant X	434.4 St	SOPS
118	Port Arthur	113 1 St	TEXI
119	Port Arthur	63 0 St	GUOC
		26 8 CT	GUOC
121	Rio Pecos	136.5 St	WETU
		5 0 CT	WETU
122	River Crest	112 5 St	TEPL
123	Riverview	34 5 St	SOPS
		27 0 CC	SOPS
126	Bertron, Sam	826.3 St	HOLP
		49 0 CT	HOLP
128	La Palma (San Benito)	219 0 St	CEPL
		54.7 CT	CEPL
129	Sandow	330 8 St	ALCA[4]
131	San Patricio	135 B IC	REME
133	Parrish, W. A.	1255 4 St	HOLP
		16 3 CT	HOLP
		1468 3 St*	HOLP
138	Stryker Creek	703 5 CT	TEPL
		10 0 IC	TEPL
144	Trinidad	412 1 St	TEPL
		4 0 IC	TEPL
148	Victoria	553 5 St	CEPL
151	Tuttle, W. D	493 9 St	SAAN
153	North Texas	75.0 St	BREP
154	Webster	614 0 St	HOLP
		16.3 CT	HOLP
157	Whitney	30 0 Hy	USAR[2]
158	Wichita Falls	25 0 St	TEES
162	Graham	634 8 St	TEES
163	Holly Street	628.0 St	AUST
164	Rayburn, Sam	52 0 Hy	USAR[2]
165	Nichols	474 8 St	SOPS
166	Pearsall	75 0 St	MECI
167	Oak Creek	81 6 St	WETU

TEXAS—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	TEXAS—Continued		
168	Valley	1175 5 St	TEPL
169	Sabine	1543 6 St	GUSU
		507 0 St*	GUSU
170	Rayburn, Sam	23.0 CT	SOTE
		25 0 St	SOTE
171	Gideon, Sim	662.0 St	LOCR
172	Toledo Bend	81.0 Hy	SARA
173	Wilkes	881 5 St	SOEP
174	Holly Ave.	51 0 CT	LUBB
		50 0 St	LUBB
		58 0 St*	LUBB
176	Braunig, Victor	894.0 St	SAAN
178	Phillips 66	32 6 CT	SOPS
180	San Angelo	32 6 CT	WETU
		100 8 St	WETU
181	Robinson, P H.	2314 5 St	HOLP
		16 3 CT	HOLP
182	Trading House Creek	1379 7 St	TEPL
183	Miller, R. W.	404 0 St	BREP
184	Olinger, Ray	345 2 St	GARL
185	Decker Creek	352 0 St	AUST
		405.0 St*	AUST
186	Cedar Bayou	2295 0 St	HOLP
188	Lewis Creek	542 9 St	GUSU
189	Jones Station	495.0 St	SOPS
190	Big Brown	1186.8 St[4]	TUSI[6]
191	Lake Hubbard	927 5 St	DAPL
192	Sommers, O W.	892.8 St	SAAN
193	Joslin, E. S.	261 0 St	CEPL
194	Ferguson, Thomas	446 4 St	LOCR
196	Monticello	1186.8 St[4]	TUSI[6]
		793.3 St*[4]	TUSI[6]
196	Texas A & M University	21 5 St	TEAM
		15.0 CT	TEAM
197	Davis, Barney M.	703 8 St	CEPL
198	Decordova	799 2 St	TEPL
199	Fort Phantom	156 6 St	WETU
		207.0 St*	WETU
200	Dansby, Roland	105 0 St*	BRYN
201	Welsh	512.0 St	SOEP
		512 0 St*	SOEP
202	Robstown	26.7 IC	ROBS
203	Martin Lake	793.0 St[4]	TUSI[6]
		1586 0 St*[4]	TUSI[6]
204	Sherwin	24.0 St	REME
		15.0 CT	REME
205	Harrington	360 0 St	SOPS
		343.0 St*	SOPS
206	Comanche Peak	2430 0 Nu*[4]	TUSI[6]
207	Deely J.T.	894 6 St*	SAAN
208	Fayette	1100 0 St*	LOCR[1]
209	Seadrift	26 8 CT	UNCH
		9.0 St	UNCH
210	Coleto Creek	550 0 St*	CEPL
211	South Texas Project	2500 0 Nu*	HOLP[5] & BREP
213	Gibbons Creek	400.0 St*	TEPA

1 Jointly owned by LOCR & AUST.
2 Power marketing under Southwestern Power Administration.
3 Power marketing under U S. Bureau of Reclamation.
4 Operated by Texas Utilities Generating Company.
5 Jointly owned by HOLP, CEPL, AUST and SAAN.
6 Holding company consisting of DAPL, TEES and TEPL

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	UTAH		
5	Carbon	188.6 St	UTPL
8	Central	175.0 St	KECC
9	Cutler	30 0 Hy	UTPL
11	Flaming Gorge	108 0 Hy	USBR
12	Gadsby	251.6 St	UTPL
15	Geneva	50 0 St	UNSS
18	Hale	59.0 St	UTPL
20	Jordan	25.0 St	UTPL
35	Huntington	892 8 St	UTPL
36	Emery	800.0 St*	UTPL
	VERMONT		
2	Bellows Falls	40.8 Hy	NEEP
14	Harriman	33.6 Hy	NEEP
17	Burlington (2 plants)	30.0 St	BULI
		26.5 CT	BULI
29	Rutland	26.2 CT	CEVP
40	Wilder	32.4 Hy[1]	NEEP
44	Vernon	563.4 Nu	VEYA
45	Berlin No. 5	48.6 CT	GRMP

1 Includes 16.2 MW on New Hampshire end of dam.

Plant No	Name of Plant	MW Capacity and Type	Utility Code
	VIRGINIA		
8	Brantly	32.5 St	DAVI
9	Bremo Bluff	254.3 St	VIEP
15	Chesterfield	1484.5 St	VIEP
16	Claytor	75.0 Hy	APPC
17	Clinch River	712.5 St	APPC
25	Glen Lyn	337.5 St	APPC
32	Kerr, John H	204.0 Hy	USAR[1]
46	Portsmouth	27.0 St	USN
47	Portsmouth	649 6 St	VIEP
		195 4 CT	VIEP
48	Possum Point	1373.0 St	VIEP
		96.0 CT	VIEP
54	Riverton	34.5 St	POEC
55	Potomac River	499 0 St	POEP
56	Smith Mountain	432 3 Hy[2]	APPC
		115.0 Hy*[2]	APPC
57	Spruance	31.9 St	DUNE
		0.3 IC	DUNE
58	Yorktown	1220.0 St	VIEP
60	Leesville	40.0 Hy	APPC
65	Surry	1718 0 Nu*	VIEP
		1695 0 Nu	VIEP
		40.1 CT	VIEP
66	North Anna	3610.0 Nu*	VIEP
69	Celco (Narrows)	25 5 St	CECA
70	Front Royal	32.5 St	AVTX

VIRGINIA—Continued

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Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	VIRGINIA—Continued		
71	Northern Neck	82.8 CT	VIEP
72	Low Moor	82 8 CT	VIEP
73	Bath County	2100.0 Hy•	VIEP[2]
74	Tasley	27.0 CT	DEPV
		1.4 IC	DEPV
75	West Point	56.8 St	CHCO
76	Franklin	56 5 St	UNCC
77	Covington	69.3 St	WEPC

[1] Power marketing under Southeastern Power Administration.
[2] Pumped Storage.

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	WASHINGTON		
1	Alder	50 0 Hy	TACO
3	Lower Baker River	64.0 Hy	PSPL
5	Box Canyon	60 0 Hy	PEOC
10	Chelan	48 0 Hy	CHPU
11	Chief Joseph	1119.0 Hy	USAR
		950 0 Hy•	USAR
14	Cushman No. 1	43.2 Hy	TACO
15	Cushman No. 2	81.0 Hy	TACO
16	Diablo	120 0 Hy	SEAT
22	Electron	25.5 Hy	PSPL
30	Gorge	143 7 Hy	SEAT
31	Grand Coulee Nos 1 & 2	4070 0 Hy[2]	USBR
31	Grand Coulee No 3	600.0 Hy•[4]	USBR
		2100 0 Hy•[4]	USBR
33	La Grande	64 0 Hy	TACO
34	Lake Union	30.0 St	SEAT
35	Little Falls	32.0 Hy	WAWP
36	Long Lake	70 0 Hy	WAWP
38	Longview	71.0 St	WETC
39	Longview	69 0 St	LOFC
40	Mayfield	121 5 Hy	TACO
41	Merwin	135 0 Hy	PAPL
59	Priest Rapids	788.5 Hy	GRCP
61	Rock Island No. 1	212.1 Hy	CHPU
		408 0 Hy•	CHPU
63	Ross	360 0 Hy	SEAT
67	Shuffleton	87 5 St	PSPL
68	Snoqualmie Falls	41.7 Hy	PSPL
72	Swift No. 1	204 0 Hy	PAPL
73	Swift No. 2	70 0 Hy	COCP[1]
75	Upper Baker River	94 4 Hy	PSPL
78	White River	70 0 Hy	PSPL
80	Yale	108 0 Hy	PAPL
82	The Dalles	1807 0 Hy	USAR
83	Rocky Reach	1213.1 Hy	CHPU
84	Ice Harbor	602 8 Hy	USAR
85	Wanapum	831 3 Hy	GRCP
86	Mossy Rock	300 0 Hy	TACO
87	Packwood	26.0 Hy	WAPS
88	Lower Monumental	405 0 Hy	USAR
		405.0 Hy•	USAR
89	Boundary	551.0 Hy	SEAT
90	Hanford Generating Project	860 0 Nu	WAPS

WASHINGTON—Continued

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	WASHINGTON—Continued		
91	Little Goose	405.0 Hy	USAR
		405.0 Hy•	USAR
92	Wells	774 3 Hy	DOPU
93	Lower Granite	405.0 Hy	USAR
		405.0 Hy•	USAR
94	Centralia	1329 8 St	PAPL[3]
95	Hanford WNP No 2	1100.0 Nu•	WAPS
96	South Whidbey Island	28.5 CT	PSPL
97	Grand Coulee P/G	100.0 Hy	USBR
		200 0 Hy•	USBR
98	Whitehorn	67 5 CT	PSPL
99	Othello	28.2 CT	WAWP
100	Hanford WNP No. 1	1250.0 Nu•	WAPS
101	Satsop WNP No. 3	1240 0 Nu•	WAPS
105	Hanford WNP No 4	1250.0 Nu•	WAPS

[1] Operated by PAPL.
[2] Includes two 10 MW station service units which can carry load.
[3] Jointly owned with WAWP, PSPL, POGE, SEAT, SNCP, TACO, & GRHC.
[4] Grand Coulee third power plant, adjacent to existing Grand Coulee No 2 power plant

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	WEST VIRGINIA		
1	Albright	209 3 St	MOPC
		69 0 St	POEC
3	Cabin Creek	170 0 St	APPC
5	South Charleston	35.0 St	FOMA
10	Kammer	712 5 St	OHPC
11	Kanawha River	439.4 St	APPC
13	Lake Lynn	51 2 Hy	WEPP
22	Sporn	305 0 St	APPC[2]
		800 6 St	OHPC[2]
23	Rivesville	109.8 St	MOPC
25	Willow Island	215 0 St	MOPC
28	Mount Storm	1662 5 St	VIEP
		18 6 CT	VIEP
29	Fort Martin	576 0 St	MOPC[3]
		576 0 St	MOPC[1]
30	Mitchell	1632 6 St	OHPC
31	Harrison	2052 0 St	MOPC[1]
32	Alloy Works	102.0 Hy	UNCA
		123 0 St	UNCA
34	Natrium	118.5 St	PIPG
35	Weirton	108 3 St	WESC
36	Amos	1632 6 St	APPC
		1300.0 St	APPC & OHPC
37	New Haven	1300.0 St•	APPC
38	Pleasants	1368.0 St•	MOPC[1]

[1] Jointly owned by MOPC, POEC, & WEPP
[2] Plant operated by Central Operating Co
[3] Jointly owned by MOPC, DULC, & POEC

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Plant No	Name of Plant	MW Capacity and Type	Utility Code
	WISCONSIN		
2	Alma	187 8 St	DAPC
		350 0 St*	DAPC
9	Bay Front	82 2 St	LASD
12	Blackhawk	0 4 Hy	WIPL
		57 5 St	WIPL
14	Blount Street	198 5 St	MAGE
26	Commerce Street	35 0 St	WIEP
34	Edgewater	128 0 St	WIPL
		351 0 St	WIPL[1]
39	French Island	22 5 St	NOSW
		187 5 CT	NOSW
40	Genoa	345 5 St	DAPC
		80 0 Nu	DAPC
49	Holcombe	33 8 Hy	NOSW
54	Kaukauna	4 8 Hy	KAUK
		6 0 IC	KAUK
		18 0 CT	KAUK
61	Lakeside	310 8 St	WIEP
		36 0 CT	WIEP
65	Manitowoc	75 0 St	MANI
66	Marshfield	50 2 St	MARF
67	Menasha	29 2 St	MENA
		0 9 IC	MENA
71	Dewey Nelson	227 3 St	WIPL
73	Oak Creek	1691 6 St	WIEP
		19 6 CT	WIEP
81	Nekoosa	3 0 Hy	NEEC
		23 5 St	NEEC
82	Port Washington	400 0 St	WIEP
		19 6 CT	WIEP
83	Prairie Du Sac	28 5 Hy	WIPL
84	Pulliam	392 5 St	WIPS
80	Rock River	159 4 St	WIPL
		131 0 CT	WIPL
98	Stoneman	51 8 St	DAPC
107	Weston	136 0 St	WIPS
		72 5 CT	WIPS
109	Winslow	26 2 St	SUWL
111	Wissota	35 3 Hy	NOSW
117	Valley	272 0 St	WIEP
		2 8 IC	WIEP
122	Kewaunee	535 0 Nu	WIPL[2]
124	Point Beach	1047 6 Nu	WIMP[3]
		19 6 CT	WIMP[3]
125	Columbia	556 0 St	WIPL[2]
		612 0 St*	WIPL[2]
126	Marinette	41 9 CT	WIPS
127	Sheepskin	46 5 CT	WIPL
128	Sycamore	36 2 CT	MAGE
129	Wheaton	321 8 CT	NOSW
130	Fitchburg	53 3 CT	MAGE
131	Figor, D J	37 6 Hy	DJFI
132	Biron	40 1 St	COCO
133	Kraft	26 5 St	COCO
134	Green Bay	56 0 St	FOHP[2]
135	Kimberly	2 7 Hy 25Hz	KICC[3]
		28 7 St	KICC[3]
136	Pleasant Prairie	617 0 St*	WIEP
137	Cornell	30 6 Hy	NOSW

[1] Jointly owned by WIPL and WIPS
[2] Jointly owned by WIPL WIPS and MAGE
[3] Jointly owned by WIMP and WIEP

Plant No.	Name of Plant	MW Capacity and Type	Utility Code
	WYOMING		
2	Alcova	36 0 Hy	USBR
7	Dave Johnston	787 0 St	PAPL
9	Fremont Canyon	48 0 Hy	USBR
15	Kortes	36.0 Hy	USBR
22	Osage	23 0 St	BLHP
		11.5 St	RUEP[1]
		1.0 IC	BLHP
28	Seminoe	32 4 Hy	USBR
33	Simpson, Neil	27.7 St	BLHP
36	Naughton	707 2 St	UTPL
41	Jim Bridger	1525.0 St	PAPL[2]
		508 0 St*	PAPL[2]
42	Wyodak	330 0 St*	BLHP[3]
43	Laramie River	500.0 St*	BAEP[4]

[1] 11,500 KW leased by Black Hills P. & L
[2] Joint ownership with IDPC.
[3] Joint ownership with PAPL.
[4] Jointly owned with TRGT and others.

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Utility Code	Type of Owner	Utility
		ALABAMA
ALEC	COOP	Alabama Electric Cooperative
ALAP	PRI	Alabama Power Company.
BACC	COOP	Baldwin County EMC.
CORN	IND	Coosa River Newsprint Co
GEPC	PRI	Georgia Power Company.
INPC	IND	International Paper Company
SCPC	IND	Scott Paper Company.
SOEG	PRI	Southern Electric Generating Company
TVA	FED	Tennessee Valley Authority
USAR	FED	United States Army
USPF	IND	United States Pipe & Foundry Co
UNSS	IND	United States Steel Corp
		ALASKA
ALEL	PRI	Alaska Electric Light & Power Co
ALLU	IND	Alaska Lumber & Pulp Co , Inc
APAD	FED	Alaska Power Administration.
ANCO	MUN	Anchorage
CHEA	COOP	Chugach Electric Assn , Inc.
COLL	MUN	Collier-Kenai.
COVE	COOP	Copper Valley Electric Assn
COPU	MUN	Cordova Public Utilities.
FACO	MUN	Fairbanks
GOVE	COOP	Golden Valley Electric Assn., Inc
HOEA	COOP	Homer Electric Assn., Inc
KECO	MUN	Ketchikan .
KEPU	IND	Ketchikan Pulp Co.
KOEA	COOP	Kodiak Electric Association, Inc
MAEA	COOP	Matanuska Electric Assn.
USN	FED	Navy, Department of the.
SIPU	MUN	Sitka
USAR	FED	United States Army
USCG	FED	United States Coast Guard.
USAF	FED	United States Government Air Force
WRLD	MUN	Wrangell
		ARIZONA
AREP	COOP	Arizona Electric Power Coop.
ARPS	PRI	Arizona Public Service Co.
CIUC	PRI	Citizens Utilities Company
INCC	IND	Inspiration Consolidated Copper Company
LOAN	MUN	Los Angeles
NAUA	MUN	Navajo Tribal Utility Authority.
NEPC	PRI	Nevada Power Company
PATU	MUN	Papago Tribal Utility
PHDC	IND	Phelps Dodge Corp.
SARV	STATE	Salt Rvr Proj., Agri Improv & Pwr Dist
SOCE	PRI	Southern California Edison Company.
SOFI	IND	Southwest Forests Inc.
TUGE	PRI	Tucson Gas & Electric Co.
USBR	FED	U.S. Bureau of Reclamation.
		ARKANSAS
AREC	COOP	Arkansas Electric Coop , Corp
ARPL	PRI	Arkansas Power & Light Co
ARMP	PRI	Arkansas-Missouri Power Co.
ARCO	PRI	Arklahoma Corporation.
CEEP	COOP	Central Electric Power Coop.
FICC	COOP	First Electric Cooperative Corp.
GEPA	IND	Georgia Pacific Corp
NOEP	COOP	N.W Electric Power Coop., Inc.
OKGE	PRI	Oklahoma Gas and Electric Company
OURU	MUN	Ouachita Electric Coop., Corp.
REME	IND	Reynolds Metals Co
SHMP	PRI	Sho-Me Power Corp
SOEP	PRI	Southwestern Electric Power Company.
SPA	FED	Southwestern Power Administration.
USAR	FED	United States Army.
		CALIFORNIA
BURB	MUN	Burbank.
CADW	STATE	California Department of Water Resources
DOCC	IND	Dow Chemical Company
ERDA	FED	Energy Research and Development Administration
LOPC	IND	Louisiana Pacific Corp.
GLPS	MUN	Glendale.
IMID	MUN	Imperial Irrigation District
KECH	IND	Kerr-McGee Chemical Corp.
LOAN	MUN	Los Angeles
MEID	MUN	Merced Irrigation District
MEWD	MUN	Metropolitan Water Dist. of Southern Cal
MOID	MUN	Modesto Irrigation District .
NEID	STATE	Nevada Irrigation District.
OASJ	MUN	Oakdale & San Joaquin Irrigation Dist.
ORWI	MUN	Orrville & Wyandotte Irrigation Dist.
PAGE	PRI	Pacific Gas and Electric Co.
PAPL	PRI	Pacific Power & Light Company
PASA	MUN	Pasadena.
PLWA	STATE	Placer County Water Agency.
SAMU	MUN	Sacramento Municipal Utility District
SADG	PRI	San Diego Gas & Electric Co.
SAFH	MUN	San Francisco, City and County of.
SIPP	PRI	Sierra Pacific Power Company.
SOCF	PRI	Southern California Edison Company.
TUID	MUN	Turlock Irrigation District
USBR	FED	U.S. Bureau of Reclamation.
YUBA	STATE	Yuba County Water Agency.

TYPE OF OWNERSHIP

PRI	Private	STATE	State or Territory
COOP	Cooperative	FED	Federal
MUN	Municipal	IND	Industrial

NOTE: The utility codes listed in this exhibit are used to identify the utilities listed on Exhibit I-4. They do not necessarily correspond to the utility code as given by the individual Reliability Councils on other Exhibits.

SOURCE: Department of Energy. "Principal Electric Facilities", DOE/EIA-0057/1-11, 1978.

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COLORADO

Utility Code	Type of Owner	Utility
CETU	PRI	Central Telephone & Utilities Corp
COFI	INO	Colorado Fuel and Iron Company
COSP	MUN	Colorado Springs.
COUE	COOP	Colorado-UTE Elec. Assn
HILE	COOP	Highline Electric Association.
INRE	COOP	Intermountain Rural Elec. Assoc
KCEA	COOP	K. C. Electric Assn
LALP	MUN	Lamar.
MOLE	COOP	Moon Lake Electric Assn.
MOPA	COOP	Mountain Parks Elec., Inc.
PRPA	STATE	Platte River Power Authority
POVA	COOP	Poudre Valley Rural Electric Assn., Inc.
PSCO	PRI	Public Service Company of Colorado.
SARV	STATE	Salt Rvr. Proj. Agri Improv & Pwr. Oist.
TRGT	COOP	Tri-State Generation & Transmission Assn
USBR	FEO	U. S. Bureau of Reclamation
USAR	FEO	United States Army
UTPL	PRI	Utah Power & Light Co
YWEA	COOP	Y. W. Electric Association, Inc.

CONNECTICUT

Utility Code	Type of Owner	Utility
BOZR	PRI	Bozrah Light and Power Co
COLP	PRI	Connecticut Light and Power Company.
COYA	PRI	Connecticut Yankee Atomic Power Co.
GROT	MUN	Groton.
HAEL	PRI	Hartford Electric Light Company
NOWI	MUN	Norwich
UNIC	PRI	United Illuminating Company
WALL	MUN	Wallingford.

OELAWARE

Utility Code	Type of Owner	Utility
OEPL	PRI	Oelmarva Power & Light Co. of Oelaware
DODE	MUN	Oover.

DISTRICT OF COLUMBIA

Utility Code	Type of Owner	Utility
PECR	IND	Penn Central Railroad.
PEOP	PRI	Potomac Electric Power Company.

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

FLORIDA

Utility Code	Type of Owner	Utility
CHEC	COOP	Choctawhatchee Electric Coop, Inc
CLEA	COOP	Clay Electric Cooperative, Inc
FLKE	COOP	Florida Keys Elec Coop Assn, Inc
FLPL	PRI	Florida Power & Light Company
FLPC	PRI	Florida Power Corporation
FOPC	MUN	Fort Pierce
GAMW	MUN	Gainesville
GUPC	PRI	Gulf Power Company.
INPC	IND	International Paper Company
JACO	MUN	Jacksonville
KEWU	MUN	Key West
LAWU	MUN	Lake Worth.
LALW	MUN	Lakeland
LECC	COOP	Lee County Electric Coop, Inc
NESB	PRI	New Smyrna Beach
ORLA	MUN	Orlando
SAJP	IND	Saint Joe Paper Company
TALL	MUN	Tallahassee
TACI	COOP	Talquin Electric Coop., Inc
TAEC	PRI	Tampa Electric Company.
USAR	FED	United States Army.
VEBM	MUN	Vero Beach
WREC	COOP	Withlacouchee River Electric Coop Inc
FLPO	PRI	Florida Public Utilities Company

GEORGIA

Utility Code	Type of Owner	Utility
CORE	COOP	Colquitt County Rural Electric Co.
GEPC	PRI	Georgia Power Company
OEMC	COOP	Oglethorpe Electric Membership Coop
SAEP	PRI	Savannah Electric & Power Co.
TVA	FEO	Tennessee Valley Authority.
USAR	FED	United States Army
MEAG	MUN	Municipal Electric Authority of Georgia
DALT	MUN	City of Dalton

HAWAII

Utility Code	Type of Owner	Utility
CIUC	PRI	Citizens Utilities Company
HELC	PRI	Hawaii Electric Light Co., Inc.
HACS	INO	Hawaiian Commercial & Sugar Co.
HAEC	PRI	Hawaiian Electric Co., Inc.
HICP	IND	Hilo Coast Processing Co
KESC	INO	Kekaha Sugar Co.
LASC	INO	Laupahoehoe Sugar Co.
LIPC	INO	Lihue Plantation Co, Ltd
MAEC	PRI	Maui Electric Co, Ltd
MBSC	INO	McBryde Sugar Co.
MOEC	PRI	Molokai Electric Co., Ltd
OASC	INO	Oahu Sugar Co, Ltd.
PIMC	INO	Pioneer Mill Co., Ltd.
PUSC	INO	Puna Sugar Co
WASC	PRI	Waialua Sugar Co, Inc
HOSC	INO	Honokaa Sugar Co

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IDAHO

Utility Code	Type of Owner	Utility
BPA	FED	Bonneville Power Administration
GEID	MUN	Gem Irrigation District
IDPC	PRI	Idaho Power Company
LORE	COOP	Lost River Electric Coop., Inc.
PAPL	PRI	Pacific Power & Light Company
RARR	COOP	Raft River Rural Electric Coop., Inc
USBR	FED	U.S. Bureau of Reclamation.
USAR	FED	United States Army
UTPL	PRI	Utah Power & Light Co
WAWP	PRI	Washington Water Power Company.

ILLINOIS

Utility Code	Type of Owner	Utility
CEIL	PRI	Central Illinois Light Company
CEIP	PRI	Central Illinois Public Service Company
CHSD	MUN	Chicago Metropolitan Sanitary Dist
COEC	PRI	Commonwealth Edison Company
CORC	IND	CPC International Inc
ELEN	PRI	Electric Energy inc
FOCM	COOP	Four County Electric Membership Corp
HIGH	MUN	Highland
ILPC	PRI	Illinois Power Company
INPD	PRI	Interstate Power Company,
IOIG	PRI	Iowa Illinois Gas and Electric Company
JAVI	MUN	Jacksonville
LIOF	IND	Libby Owens Ford Glass Co.
PERU	MUN	Peru
ROCL	MUN	Rochelle
SOIP	COOP	Southern Illinois Power COOP
SPFI	MUN	Springfield
UNEC	PRI	Union Electric Co
UNSS	IND	United States Steel Corp
UNIL	STATE	University of Illinois.
WEIL	COOP	Western Illinois Power COOP inc
WINK	MUN	Winnetka

INDIANA

Utility Code	Type of Owner	Utility
ALCO	IND	Alcoa Generating Corp
AMOC	IND	AMOCO Oil Company
COEO	PRI	Commonwealth Edison Co of Indiana inc
CRAW	MUN	Crawfordsville
FOWA	MUN	Fort Wayne
FRAF	MUN	Frankfort
ICIU	IND	ICI United States inc
INME	PRI	Indiana & Michigan Electric Co
INSR	COOP	Indiana Statewide R E C .
INKE	PRI	Indiana Kentucky Electric Corp
INPL	PRI	Indianapolis Power & Light Co
INST	IND	Inland Steel Co
LOSP	MUN	Logansport
MIPC	PRI	Miami Power Corp
NOIP	PRI	Northern Indiana Public Service Company
PERI	MUN	Peru.
PSIN	PRI	Public Service Co of Indiana
RICI	MUN	Richmond,
SOIG	PRI	Southern Indiana Gas & Electric Co
UNSS	IND	United States Steel Corp
YOST	IND	Youngstown Sheet and Tube Co

IOWA

Utility Code	Type of Owner	Utility
AMES	MUN	Ames
CEFA	MUN	Cedar Falls
CEIC	COOP	Central Iowa Power Coop
CLCC	IND	Clinton Corn Processing
COBP	COOP	Corn Belt Power Coop
EAIL	COOP	Eastern Iowa Light & Power Cooperative
INPD	PRI	Interstate Power Company
IOEL	PRI	Iowa Electric Light and Power Company
IOPL	PRI	Iowa Power and Light Company
IOPS	PRI	Iowa Public Service Company
IOSU	PRI	Iowa Southern Utilities Company.
IOIG	PRI	Iowa-Illinois Gas and Electric Company
LOPO	COOP	Land O Power Coop , Inc.
MUSC	COOP	Muscatine
PELL	MUN	Pella.
SPEN	MUN	Spencer
USBR	FED	U.S. Bureau of Reclamation
UNEC	PRI	Union Electric Co.
WECI	MUN	Webster City

KANSAS

Utility Code	Type of Owner	Utility
CEKE	COOP	Central Kansas Electric Coop., Inc.
CEKP	PRI	Central Kansas Power Co
CETU	PRI	Central Telephone & Utilities Corp.
COFF	MUN	Coffeyville
EMDE	PRI	Empire District Electric Co
KACY	MUN	Kansas City
KACP	PRI	Kansas City Power & Light Company
KAGE	PRI	Kansas Gas and Electric Company
KAPL	PRI	Kansas Power and Light Company
MCPH	MUN	McPherson.
OTTA	MUN	Ottawa
PICA	COOP	Pioneer Cooperative Association, Inc.
PRAT	MUN	Pratt.
SUNC	COOP	Sunflower Electric Coop.
WELL	MUN	Wellington
WHEI	COOP	Wheatland Electric Coop , Inc.
WINF	MUN	Winfield

KENTUCKY

Utility Code	Type of Owner	Utility
BIRI	COOP	Big Rivers Rural Electric Coop Corp
EAKR	COOP	East Kentucky Power Coop Inc
ELNE	PRI	Electric Energy Inc
HEND	MUN	Henderson.
KEPC	PRI	Kentucky Power Company.
KEUC	PRI	Kentucky Utilities Company.
LOGE	PRI	Louisville Gas and Electric Co
OHVE	PRI	Ohio Valley Electric Corp
OWEN	MUN	Owensboro.
TVA	FED	Tennessee Valley Authority
UNLH	PRI	Union Light, Heat and Power Company.
USAR	FED	United States Army
WARU	COOP	Warren Rural Electric Coop Corp

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

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LOUISIANA

Utility Code	Type of Owner	Utility
ALEX	MUN	Alexandria.
CAJU	COOP	Cajun Electric Power Coop , Inc
CELE	PRI	Central Louisiana Electric Co
CIGE	IND	Cities Service Refining Corporation
CRZE	IND	Crown Zellerback Corp.
DDCC	IND	Dow Chemical Company.
FRAN	MUN	Franklin
GUSU	PRI	Gulf States Utilities Company.
HOUM	MUN	Houma
INPC	IND	International Paper Company
JEDE	COOP	Jefferson Davis Electric Coop., Inc.
KACC	IND	Kaiser Aluminum & Chemical Corp
LAFA	MUN	Lafayette.
LOPL	PRI	Louisiana Power & Light Company
MIND	MUN	Minden
MONR	MUN	Monroe
MOCI	MUN	Morgan City
NATC	MUN	Natchitoches.
NEOP	PRI	New Orleans Public Service, Inc.
NEOS	MUN	New Orleans Sewerage and Water Board.
OPEL	MUN	Opelousas
PIPG	IND	Pittsburgh Plate Glass Co.
PLAQ	MUN	Plaquemine.
RUST	MUN	Ruston.
SOLE	CODP	Southwest La Elec Membership Corp.
SOEP	PRI	Southwestern Electric Power Company

MAINE

Utility Code	Type of Owner	Utility
BAHE	PRI	Bangor Hydro-Electric Company
BOCA	IND	Boise Cascade Paper Group
CAMP	PRI	Central Maine Power Company.
GEPA	IND	Georgia Pacific Corp.
GRNP	IND	Great Northern Paper Co.
INPC	IND	International Paper Company.
MAPO	PRI	Maine Electric Power Co., Inc.
MAPS	PRI	Maine Public Service Company.
MAYA	PRI	Maine Yankee Atomic Power Co.
WASD	IND	Warren Co., S. D.

MARYLAND

Utility Code	Type of Owner	Utility
BAGE	PRI	Baltimore Gas & Electric Co.
BESC	IND	Bethlehem Steel Corporation.
DEPM	PRI	Delmarva Power & Light Co. of Maryland .
EAUC	MUN	Easton Utility Commission
GEEC	IND	General Electric Company
PECR	IND	Penn Central Railroad.
POEC	PRI	Potomac Edison Co.
POEP	PRI	Potomac Electric Power Company
SOME	COOP	Southern Maryland Electric Coop., Inc.
SUEC	PRI	Susquehanna Electric Company.
USAR	FED	United States Army
WEPC	IND	Westvaco Corp.

MASSACHUSETTS

Utility Code	Type of Owner	Utility
BOEC	PRI	Boston Edison Company
BRAI	MUN	Braintree
BREC	PRI	Brockton Edison Company
CAEL	PRI	Cambridge Electric Light Co.
CACD	PRI	Canal Electric Co.
FARE	PRI	Fall River Electric Light Company
FIGE	PRI	Fitchburg Gas and Electric Light Co.
GEEC	IND	General Electric Company.
HOLM	MUN	Holyoke.
HOWP	PRI	Holyoke Water Power Co.
MABT	MUN	Mass. Bay Transportation Authority
MASE	PRI	Massachusetts Electric Co.
MMWE	PRI	Mass. Municipal Wholesale Electric Co.
MOEL	PRI	Montaup Electric Company.
NEBG	PRI	New Bedford Gas and Edison Light Company.
NEEP	PRI	New England Power Company
PEAB	MUN	Peabody.
SPRD	MUN	Springfield
TAUN	MUN	Taunton
WEME	PRI	Western Massachusetts Electric Company.
YAEC	PRI	Yankee Atomic Electric Co.

MICHIGAN

Utility Code	Type of Owner	Utility
COPR	PRI	Consumers Power Co
DETR	MUN	Detroit.
DEEC	PRI	Detroit Edison Co.
DOCC	IND	Dow Chemical Company.
EDSE	PRI	Edison Sault Electric Co
FOMC	IND	Ford Motor Company
HOLL	IND	Holland
HUPO	IND	Huron Portland Cement Co
INME	PRI	Indiana & Michigan Electric Co
LABW	MUN	Lansing
MARQ	MUN	Marquette
MECP	IND	Mead Corp
MISU	STATE	Michigan State University
NOMC	COOP	Northern Michigan Electric COOP.
TRAV	MUN	Traverse City.
UNMI	STATE	University of Michigan.
UPGC	PRI	Upper Peninsula Generating Co
UPPP	PRI	Upper Peninsula Power Co
WHPC	IND	White Pine Copper Co
WIMP	PRI	Wisconsin Michigan Power Co
WOEL	COOP	Wolverine Electric Cooperative
WYAN	MUN	Wyandotte

MINNESOTA

Utility Code	Type of Owner	Utility
AUMI	MUN	Austin.
COLC	COOP	Cooperative Power Association,
DAPC	COOP	Dairyland Power Cooperative
EARE	COOP	East River Elec Power Coop
ERMC	IND	Erie Mining Co
INPD	PRI	Interstate Power Co
MIPL	PRI	Minnesota Power & Light Co
MIPI	COOP	Minnkota Power Cooperative, Inc
MOOR	MUN	Moorhead.
NEWU	MUN	New Ulm.
OTTP	PRI	Otter Tail Power Company
OWAT	MUN	Owatonna.
REMC	IND	Reserve Mining Co
ROCH	MUN	Rochester.
SQSE	COOP	Square Butte Elec COOP, Inc.
USBR	FED	U S Bureau of Reclamation
UNPA	COOP	United Power Association
VIRG	MUN	Virginia.
WILM	MUN	Wilmar

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

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Utility Code	Type of Owner	Utility
		MISSISSIPPI
CLWL	MUN	Clarksdale.
GRUT	MUN	Greenwood.
MACO	IND	Masonite Corp.
MIPO	PRI	Mississippi Power & Light Company
MIPR	PRI	Mississippi Power Company.
PERV	COOP	Pearl River Valley Electric Pwr Assn
SOMI	COOP	South Mississippi Electric Pwr Assn
SOPE	COOP	Southern Pine EPA
TVA	FED	Tennessee Valley Authority
YACP	MUN	Yazoo City
		MISSOURI
ARPL	PRI	Arkansas Power & Light Co.
ARMP	PRI	Arkansas-Missouri Power Co.
ASEC	COOP	Associated Electric Coop.
CART	MUN	Carthage
CEEP	COOP	Central Electric Power Coop.
COLM	MUN	Columbia
EMDE	PRI	Empire District Electric Co.
FULT	MUN	Fulton.
HANN	MUN	Hannibal
INDN	MUN	Independence
KACP	PRI	Kansas City Power & Light Company
KENN	MUN	Kennett Municipal
MAEP	COOP	M. and A. Electric Power Coop.
MARM	MUN	Marshall
MILC	PRI	Missouri Power & Light
MIPU	PRI	Missouri Public Service Company
MIUC	PRI	Missouri Utilities Company.
NOEP	COOP	N. W. Electric Power Coop., Inc.
NEMA	MUN	New Madrid.
NOMP	COOP	Northeast Missouri Electric Power Coop.
SAJL	PRI	Saint Joseph Light & Power Company
SHMP	PRI	Sho-me Power Corp.
SIKE	MUN	Sikeston.
SPRM	MUN	Springfield
UNEC	PRI	Union Electric Co.
USAR	FED	United States Army
		MONTANA
BPA	FED	Bonneville Power Administration.
GLCE	COOP	Glacier Electric Coop., Inc.
MOPO	PRI	Montana Power Co.
MODU	PRI	Montana-Dakota Utilities Co.
PAPL	PRI	Pacific Power & Light Company
PSPL	PRI	Puget Sound Power & Light Company
USBR	FED	U. S. Bureau of Reclamation
USAR	FED	United States Army
WAWP	PRI	Washington Water Power Company.

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

Utility Code	Type of Owner	Utility
		NEBRASKA
BLHP	PRI	Black Hills Power and Light Company
CENP	STATE	Central Nebraska Pub. Power & Irr. Dist.
CUCP	STATE	Custer Public Power Dist.
FREM	MUN	Fremont.
GRIS	MUN	Grand Island.
HAST	MUN	Hastings
LINK	MUN	Lincoln.
LORP	STATE	Loup River Public Power District.
NEGT	COOP	Nebraska Electric Gen. & Trans Coop.
NEPP	STATE	Nebraska Public Power System.
OMPP	STATE	Omaha Public Power District
TRGT	COOP	Tri-State Generation & Transmission Assn.
USBR	FED	U. S. Bureau of Reclamation.
USAR	FED	United States Army.
		NEVADA
BURB	MUN	Burbank.
GLPS	MUN	Glendale
HARN	COOP	Harney Electric Coop., Inc.
IDPC	PRI	Idaho Power Company
KECC	IND	Kennecott Copper Corp.
LOAN	MUN	Los Angeles.
MEWD	MUN	Metropolitan Water Dist. of Southern Cal.
NEPC	PRI	Nevada Power Company.
PASA	MUN	Pasadena
SARV	STATE	Salt Rvr Proj. Agri Improv & Pwr Dist.
SIPP	PRI	Sierra Pacific Power Company
SOCE	PRI	Southern California Edison Company
USBR	FED	U.S. Bureau of Reclamation.
VAEA	COOP	Valley Electric Assn., Inc.
		NEW HAMPSHIRE
BRCO	IND	Brown Company
NEEP	PRI	New England Power Company
PSNH	PRI	Public Service Company of New Hampshire.
		NEW JERSEY
ATCE	PRI	Atlantic City Electric Company.
JECP	PRI	Jersey Central Power & Light Company.
MOOC	IND	Mobile Oil Corp.
PSEG	PRI	Public Service Electric and Gas Company.
VINE	MUN	Vineland.

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Utility Code	Type of Owner	Utility
		NEW MEXICO
ARPS	PRI	Arizona Public Service Co
COPS	PRI	Community Public Service Company.
ELPE	PRI	El Paso Electric Company
ERDA	FED	Energy Research and Development Administration.
FATN	MUN	Farmington.
LECE	COOP	Lea County Electric Coop
NEME	PRI	New Mexico Electric Service Company.
PLEG	COOP	Plains Electric Gen. & Trans Coop., Inc.
PSNM	PRI	Public Service Company of New Mexico
SARV	STATE	Salt Rvr Proj, Agri Improv & Pwr Dist
SOCE	PRI	Southern California Edison Company.
SOPS	PRI	Southwestern Public Service Co.
TUGE	PRI	Tucson Gas & Electric Co.
USBR	FED	U.S Bureau of Reclamation.
		NEW YORK
ALCC	IND	Allied Chemical Corp
BESC	IND	Bethlehem Steel Corporation.
CEHG	PRI	Central Hudson Gas & Electric Corp.
COEN	PRI	Consolidated Edison Company of New York
EAKC	IND	Eastman Kodak Company
FREP	MUN	Freeport
GEEC	IND	General Electric Company
INPC	IND	International Paper Company
JAME	MUN	Jamestown
LOIL	PRI	Long Island Lighting Company
NALC	IND	National Lead Company
NEYE	PRI	New York State Electric & Gas Corp.
NIMP	PRI	Niagara-Mohawk Power Corporation
ORRU	PRI	Orange & Rockland Utilities, Inc
PLAT	MUN	Plattsburg
POAS	STATE	Power Authority of the State of New York
ROGE	PRI	Rochester Gas and Electric Corporation.
ROCK	MUN	Rockville Centre
		NORTH DAKOTA
BAEP	COOP	Basin Electric Coop.
CEPE	COOP	Central Power Electric Coop., Inc.
COLC	COOP	Cooperative Power Association
MIPI	COOP	Minnkota Power Cooperative, Inc.
MOOU	PRI	Montana-Dakota Utilities Co.
MOGS	COOP	Mor-Gran-Sou Electric Coop., Inc.
NOSM	PRI	Northern States Power Co.-Minnesota
OTTP	PRI	Otter Tail Power Company
SQBE	COOP	Square Butte Electric Coop
USBR	FED	U. S. Bureau of Reclamation
UNPA	COOP	United Power Association
USAR	FED	United States Army

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

Utility Code	Type of Owner	Utility
		NORTH CAROLINA
AMEC	IND	American Enka Corporation
BLRI	COOP	Blue Ridge Electric Membership Corp
BREM	COOP	Brunswick Electric Membership Corp.
CAHE	COOP	Cape Hatteras Electric Membership Corp.
CAPO	PRI	Carolina Power & Light Company.
CHPA	IND	Champion Papers Inc
DAEL	COOP	Davidson Electric Membership Corp
DUPC	PRI	Duke Power Company
FAWL	MUN	Farmville
FRBM	COOP	French Broad Electric Membership Corp
LURC	COOP	Lumbee River Electric Membership Corp
NAPL	PRI	Nantahala
RAEM	COOP	Randolph Electric Membership Corp
TAPI	PRI	Tapoco Inc
TVA	FED	Tennessee Valley Authority.
UNNC	STATE	University of North Carolina
VIEP	PRI	Virginia Electric and Power Company
WAEM	COOP	Wake Electric Membership Corp
YADI	IND	Yadkin, Inc
		OHIO
BUPI	COOP	Buckeye Power Inc
CELI	MUN	Celina
CIGE	PRI	Cincinnati Gas & Electric Co
CLEV	MUN	Cleveland.
CLEI	PRI	Cleveland Electric Illuminating Co
COSO	PRI	Columbus and Southern Ohio Elec Co
COLU	MUN	Columbus
OAPO	PRI	Dayton Power & Light Co
DOVE	MUN	Dover
FITR	IND	Firestone Tire and Rubber Co
GOTR	IND	Goodyear Tire and Rubber Co
HAMI	MUN	Hamilton
LIOF	IND	Libby Owens Ford Glass Co.
MECP	IND	Mead Corp
OHEC	PRI	Ohio Edison Co
OHEL	PRI	Ohio Electric Co
OHPC	PRI	Ohio Power Co
OHVE	PRI	Ohio Valley Electric Corp
ORRV	MUN	Orrville.
PAIN	MUN	Painesville.
PIQU	MUN	Pique.
PIPG	IND	Pittsburg Plate Glass Industries, Inc
RESC	IND	Republic Steel Corporation.
SHBY	MUN	Shelby.
TOEC	PRI	Toledo Edison Co
UNCA	IND	Union Carbide Corp
UNSS	IND	United States Steel Corp
WHEC	PRI	Wheeling Electric Company
YOST	IND	Youngstown Sheet and Tube Co

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Utility Code	Type of Owner	Utility
		OKLAHOMA
ARCO	PRI	Arklahoma Corporation
GRRD	STATE	Grand River Dam Authority.
KAMO	COOP	Kamo Electric Coop., Inc
OKGE	PRI	Oklahoma Gas and Electric Company.
PONC	MUN	Ponca City
PSOK	PRI	Public Service Company of Oklahoma.
SOEP	PRI	Southwestern Electric Power Company.
SPA	FED	Southwestern Power Administration.
SOPS	PRI	Southwestern Public Service Co.
USAR	FED	United States Army
WEFA	COOP	Western Farmers Electric Coop., Inc
		OREGON
BALC	IND	Bate, J. Hubert, Lumber Co.
BPA	FED	Bonneville Power Administration.
CAUC	PRI	California-Pacific Utilities Co
CELP	MUN	Central Lincoln Peoples Utility District.
CHMS	IND	Chicago, Mil., St. Paul & Pacific Rail.
CLCU	MUN	Clark County Public Utility District No. 1.
COCU	COOP	Coos-Curry Electric Coop., Inc.
COPO	COOP	Consumers Power Inc
EUGE	MUN	Eugene Water & Electric Board.
HARN	COOP	Harney Electric Coop., Inc.
IDPC	PRI	Idaho Power Company
MIEC	COOP	Midstate Electric Coop., Inc
PAPL	PRI	Pacific Power & Light Company
PDGE	PRI	Portland General Electric Company
ROLC	IND	Roseburg Lumber Co.
USBR	FED	U.S Bureau of Reclamation.
UMEC	COOP	Umatilla Electric Coop Assn.
USAR	FED	United States Army
WETC	IND	Weyerhaeuser Timber Company
		PENNSYLVANIA
ARPO	IND	ARCO/Polymers Inc.
BESC	IND	Bethlehem Steel Corporation.
DULC	PRI	Duquesne Light Company.
GUDC	IND	Gulf Oil Corp.
HAPA	IND	Hammermill Paper Co.
JDLS	IND	Jones & Laughlin Steel Co.
MEEC	PRI	Metropolitan Edison Company.
PECR	IND	Penn Central Railroad.
PEEC	PRI	Pennsylvania Electric Company
PEPL	PRI	Pennsylvania Power & Light Company
PEPC	PRI	Pennsylvania Power Company
PHEC	PRI	Philadelphia Electric Company.
SAHW	PRI	Safe Harbor Water Power Corporation
SAJC	IND	Saint Joseph Minerals Co
UNGI	PRI	UGI Corporation.
UNSS	IND	United States Steel Corp
WEPP	PRI	West Penn Power Company
WECO	IND	Westinghouse Electric Corp.

Utility Code	Type of Owner	Utility
		RHODE ISLAND
BLVG	PRI	Blackstone Valley Electric Company.
NAEC	PRI	Narragansett Electric Company
NEWP	PRI	Newport Electric Corp.
		SOUTH CAROLINA
CAPO	PRI	Carolina Power & Light Company.
CEPC	COOP	Central Electric Power Coop
DUPC	PRI	Duke Power Company
GEPC	PRI	Georgia Power Company
GRMI	COOP	Greenwood Mills
PAEI	COOP	Palmetto Electric Coop, Inc
SOPC	IND	Sonoco Products Company
SOCG	PRI	South Carolina Electric & Gas Company
SOCA	STATE	South Carolina Public Service Authority
USBR	FED	U S Bureau of Reclamation
USAR	FED	United States Army
WEPC	IND	Vestvaco Corp
		SOUTH DAKOTA
BAEP	COOP	Basin Electric Coop
BLHP	PRI	Black Hills Power and Light Company
EARE	COOP	East River Elec. Power Coop.
LOPD	COOP	L. and O. Power Coop, Inc.
MODU	PRI	Montana-Dakota Utility Co.
NEPP	STATE	Nebraska Public Power District
NOSM	PRI	Northern States Power Co.-Minnesota.
NOPS	PRI	Northwestern Public Service Co.
OTTP	COOP	Otter Tail Power Company.
USBR	FED	U. S. Bureau of Reclamation.
USAR	FED	United States Army.
		TENNESSEE
APPC	PRI	Appalachian Power Co
USAT	FED	Atomic Energy Commission.
BOSP	IND	Bowaters Southern Paper Corp
CHEP	MUN	Chattanooga.
KNUB	MUN	Knoxville Utilities Board.
MELG	MUN	Memphis.
NAES	MUN	Nashville & Davidson Co Elec. Pwr.
PDVE	COOP	Powell Valley Electric Cooperative
TAPI	PRI	Tapoco Inc.
TVA	FED	Tennessee Valley Authority
USAR	FED	United States Army

TYPE OF OWNERSHIP

PRI	Private	STATE	State or Territory
COOP	Cooperative	FED	Federal
MUN	Municipal	IND	Industrial

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EXHIBIT **I–5**

Utility Code	Type of Owner	Utility
		TEXAS
ALCA	IND	Aluminum Company of America
AUST	MUN	Austin
BREP	COOP	Brazos Electric Power Coop., Inc
BROV	MUN	Brownsville
BRYN	MUN	Bryan.
CEPL	PRI	Central Power and Light Company
CETE	COOP	Central Texas Electric Coop , Inc.
COPS	PRI	Community Public Service Company.
DAPL	PRI	Dallas Power & Light Co
DETE	COOP	Deep East Texas Electric Coop., Inc.
DENT	MUN	Denton
DOCC	IND	Dow Chemical Company.
ELPE	PRI	El Paso Electric Company
EXCO	PRI	Exxon Corp.
GARL	MUN	Garland.
GRUO	MUN	Greenville .
GUVA	COOP	Guadalupe Valley Elec Coop , Inc.
GUOC	IND	Gulf Oil Corporation .
GUPC	PRI	Gulf Power Company
GUSU	PRI	Gulf States Utilities Company .
HOLP	PRI	Houston Lighting & Power Company
INBW	FED	International Boundary and Water Comm.
LECE	COOP	Lea County Electric Coop
LOSS	IND	Lone Star Steel Corporation.
LOCR	STATE	Lower Colorado River Authority.
LUBB	MUN	Lubbock.
MECI	COOP	Medina Electric Cooperative, Inc.
MOOC	IND	Mobil Oil Corp
PECI	COOP	Pedernales Elec Coop., Inc
PETE	IND	Petro-Tex Chemical Corp
REME	IND	Reynolds Metals Co.
RIGE	COOP	Rio Grande Electric Cooperative.
ROBS	MUN	Robstown
RUEP	COOP	Rushmore Electric Power Coop., Inc.
SARA	STATE	Sabine River Auth of Texas & Louisiana
SAAN	MUN	San Antonio.
SABE	COOP	San Bernard Electric Coop , Inc
SOTE	COOP	South Texas Electric Coop., Inc
SOPM	IND	Southland Paper Mills.
SOEP	PRI	Southwestern Electric Power Company.
SOPS	PRI	Southwestern Public Service Co
TEXI	IND	Texaco Inc.
TEAM	STATE	Texas A & M University
TEES	PRI	Texas Electric Service Company
TEPA	MUN	Texas Municipal Power Agency
TEPL	PRI	Texas Power & Light Company
TUSI	PRI	Texas Utilities Company System.
UNCH	IND	Union Carbide Chemical Co.
USAR	FED	United States Army
UPRE	COOP	Upshur Rural Electric Coop., Corp
WETU	PRI	West Texas Utilities Company.
WEFA	COOP	Western Farmers Electric Coop.
WOCE	COOP	Wood County Elec. Coop., Inc

Utility Code	Type of Owner	Utility
		UTAH
CAUC	PRI	California-Pacific Utilities Co.
GAPA	COOP	Garkane Power Association, Inc.
KECC	IND	Kennecott Copper Corp
LOAN	MUN	Los Angeles.
MOLE	COOP	Moon Lake Electric Assn., Inc.
NEPC	PRI	Nevada Power Company.
RARR	COOP	Raft River Rural Elec Coop Inc.
UNSS	IND	United States Steel Corp
UTPL	PRI	Utah Power & Light Co
USBR	FED	U. S. Bureau of Reclamation
		VERMONT
BULI	MUN	Burlington.
CEVP	PRI	Central Vermont Public Service Corp.
GRMP	PRI	Green Mountain Power Corporation
NEEP	PRI	New England Power Company
VEPI	PRI	Vermont Electric Power Co.
VEYA	PRI	Vermont Yankee Nuclear Power Corp.
		VIRGINIA
APPC	PRI	Appalachian Power Co.
AVTX	IND	Avtex Fibers Inc.
CECA	IND	Celanese Corp. of American.
CEVC	COOP	Central Virginia Electric Coop.
CHCO	IND	Chesapeake Corp of Virginia.
DAVI	MUN	Danville .
DEPV	PRI	Delmarva Power & Light Co of Virginia.
DUNE	IND	Du Pont De Nemours, E I., and Company.
MECH	COOP	Mecklenburg Electric Coop., Inc.
USN	FED	Navy, Department of the.
OLDP	PRI	Old Dominion Power Company.
POEC	PRI	Potomac Edison Co.
POEP	PRI	Potomac Electric Power Company
SHVE	COOP	Shenandoah Valley Electric Cooperative.
TVA	FED	Tennessee Valley Authority.
UNCC	IND	Union Camp Corp.
USAR	FED	United States Army.
VIEP	PRI	Virginia Electric and Power Company.
VIEC	COOP	Virginia Electric Coop
WEVA	IND	Westvaco Corp.

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

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Utility Code	Type of Owner	Utility
		WASHINGTON
BECP	MUN	Benton County Public Utility District No. 1.
BPA	FED	Bonneville Power Administration.
CHPU	MUN	Chelan County Public Utility District No 1
CLCP	MUN	Clallam County Public Utility District No. 1.
CLCU	MUN	Clark County Public Utility District No. 1.
COCP	MUN	Cowlitz County Public Utility Dist No. 1
DOPU	MUN	Douglas County P.U.D. No. 1.
ERDA	FED	Energy Research and Development Administration.
GRCP	MUN	Grant County P.U.D. No. 2.
GRHC	MUN	Grays Harbor County Pub Utility Dist No. 1
KLCP	MUN	Klickitat County Public Utility Dist No 1
LOFC	IND	Longview Fibre Co.
USN	FED	Navy, Department of the.
NEVE	COOP	Nespelem Valley Electric Coop., Inc.
OKCP	MUN	Okanogan County Public Utility Dist No. 1.
PAPL	PRI	Pacific Power & Light Company.
PEOC	MUN	Pend Oreille County P.U.D No. 1.
PSPL	PRI	Puget Sound Power & Light Company.
SEAT	MUN	Seattle City Light.
SNCP	MUN	Snohomish County Public Utility District 1.
TACO	MUN	Tacoma City Light.
USBR	FED	U.S. Bureau of Reclamation.
USAR	FED	United States Army.
WAPS	MUN	Washington Public Power Supply System.
WAWP	PRI	Washington Water Power Company, The.
WETC	IND	Weyerhaeuser Timber Company.
		WEST VIRGINIA
APPC	PRI	Appalachian Power Co.
FOMA	IND	Food Machinery & Chemical Corp.
MOPC	PRI	Monongahela Power Company.
OHPC	PRI	Ohio Power Co
PIPG	IND	Pittsburg Plate Glass Industries Inc.
POEC	PRI	Potomac Edison Co.
UNCA	IND	Union Carbide Corp N9.
VIEP	PRI	Virginia Electric and Power Company,
WESC	IND	Weirton Steel Co.
WEPP	PRI	West Penn Power Company.
WHEC	PRI	Wheeling Electric Company

Utility Code	Type of Owner	Utility
		WISCONSIN
COCO	IND	Consolidated Papers, Inc
COWP	PRI	Consolidated Water Power Co.
DAPC	COOP	Dairyland Power Cooperative
DJFI	IND	Figor, O J
FOHP	IND	Fort Howard Paper Co
KAUK	MUN	Kaukauna.
KICC	IND	Kimberly Clark Corp
LASD	PRI	Lake Superior Dist Power Co
MAGE	PRI	Madison Gas and Electric Co
MANI	MUN	Manitowoc
MARF	MUN	Marshfield
MENA	MUN	Menasha.
NEEC	IND	Nekoosa Edwards Paper Co
NOSW	PRI	Northern States Power Co Wisconsin
SUWL	PRI	Superior Water, Light, and Power Co.
WIEP	PRI	Wisconsin Electric Power Co
WIMP	PRI	Wisconsin Michigan Power Co
WIPL	PRI	Wisconsin Power and Light Co
WIPS	PRI	Wisconsin Public Service Corp
		WYOMING
BAEP	COOP	Basin Elec Power Coop.
BLHP	PRI	Black Hills Power and Light Company
BPA	FED	Bonneville Power Administration.
CAPL	COOP	Carbon Power and Light, Inc.
IDPC	PRI	Idaho Power Company
LOVP	COOP	Lower Valley Power & Light Inc.
PAPL	PRI	Pacific Power & Light Company
RUEP	COOP	Rushmore Electric Power Coop, Inc.
TRCO	COOP	Tri-County Electric Assn., Inc.
TRGT	COOP	Tri-State Generation & Transmission Assn.
USBR	FED	U. S Bureau of Reclamation.
UTPL	PRI	Utah Power & Light Co.

TYPE OF OWNERSHIP

PRI	Private
COOP	Cooperative
MUN	Municipal
STATE	State or Territory
FED	Federal
IND	Industrial

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EXHIBIT I–5

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND ECAR REGIONAL REPORT

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ECAR**	
CONTRACT NO. DACW72-78-C-0013 DATE: MARCH, 1979	EXHIBIT II-1

ECAR - REPORTING UTILITIES

Letter Code	Sub-Region
APS	ALLEGHENY POWER SYSTEM
	Members of ECAR:
MOPC	Monongahela Power Company
POEC	Potomac Edison Company
WEPP	West Penn Power Company
AEP	AMERICAN ELECTRIC POWER SYSTEM
	Members of ECAR:
APPC	Appalachian Power Company
INME	Indiana and Michigan Electric Company
KEPC	Kentucky Power Company
OHPC	Ohio Power Company
CAPCO	CENTRAL AREA POWER COORDINATION GROUP
	Members of ECAR:
CEI	Cleveland Electric Illuminating Company
DLCO	Duquesne Light Company
OE	Ohio Edison System
PEPC	Pennsylvania Power Company
TECO	Toledo Edison Company
CCD	CINCINNATI COLUMBUS DAYTON GROUP
	Members of ECAR:
CG&E	Cincinnati Gas and Electric Company
CSOE	Columbus and Southern Ohio Electric Company
DP&L	Dayton Power and Light Company

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LIST OF UTILITIES

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CONTRACT NO DACW72 - 78 - C - 0013
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EXHIBIT II-2

ECAR - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
KY-IND	KENTUCKY - INDIANA GROUP
	Members of ECAR:
EKPC	East Kentucky Power Cooperative
IP&L	Indianapolis Power and Light Company
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
NIPS	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
	Indiana-Kentucky Electric Company
PSI	Public Service Company of Indiana
SIGE	Southern Indiana Gas and Electric Company
MECS	MICHIGAN ELECTRIC COORDINATED SYSTEM
	Members of ECAR:
CP	Consumers Power Company
DECO	Detroit Edison Company
LIAS	ECAR LIAISON MEMBER SYSTEMS
BIRI	Big Rivers Electric Corporation
BUCK	Buckeye Power, Incorporated
CLEV	City of Cleveland - Division of Light and Power
DPLD	City of Detroit - Public Lighting Department
ESEC	Edison Sault Electric Company
HAMI	Hamilton Department of Public Utilities - Electric Div.
HMPL	Henderson Municipal Power & Light
HED	Hoosier Energy Division of Indiana Statewide REC, Inc.
LBWL	Lansing Board of Water and Light
MMCP	Michigan Municipal Cooperative Pool
CONA	Conalco
GHLP	Grand Haven Board of Light & Power
HART	Hart Hydro Electric

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EXHIBIT II-2

ECAR - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
LIAS	ECAR LIAISON MEMBER SYSTEMS (Cont'd)
LL&P	Lowell Light & Power
NMEC	Northern Michigan Electric Cooperative, Inc.
TCLP	Traverse City Light & Power Department
WEC	Wolverine Electric Cooperative
ZBPW	Zeeland Board of Public Works
OMU	Owensboro Municipal Utilities
RP&L	Richmond Power and Light
WVPA	Wabash Valley Power Association

Source: ECAR "Coordinated Regional Bulk Power Supply Programs," Volumes I & II, April 1978.

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ECAR

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

Calendar Year	Thousands of GWh	Annual Energy Average Annual Growth Rate-% 1 yr	Annual Energy Average Annual Growth Rate-% 5 yr	Peak GW	Peak Demand Average Annual Growth Rate-% 1 yr	Peak Demand Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
1965 1/	180.5			31.1			66.3
1966 2/	207.9	15.2		33.9	9.0		70.0
1967 2/	215.6	3.7		35.1	3.5		70.1
1968 2/	231.7	7.5		38.4	0.4		68.7 3/
1969 4/	240.0	3.6		39.0	1.6		70.2
1970	262.0	9.2	7.7	43.0	10.3	6.7	69.6
1971	274.0	4.6	5.7	46.0	7.0	6.3	68.0
1972	299.0	9.1	6.8	49.0	6.5	6.9	69.5 3/
1973	325.0	8.7	7.0	55.0	12.2	7.4	67.5
1974	324.0	(0.3)	6.2	53.0	(3.6)	6.3	69.8
1975	321.0	(0.9)	4.1	55.0	3.8	5.0	66.6
1976 5/	327.2	1.9	3.6	56.9	3.5	4.3	65.5 3/
1977 6/	347.2	6.1	3.0	59.5	4.6	4.0	66.6

1/ 1970 National Power Survey, Part II (FPC).
2/ Semi-Annual Electric Power Survey, Edison Electric Institute.
3/ Load Factor is based on 8784 hours to account for leap year.
4/ FPC (1976) "Electric Power Statistics" (1969-75), June.
5/ FPC, Form 12.
6/ ECAR (1978) "Coordinated Regional Bulk Power Supply Programs," ECAR information report pursuant to December 27, 1977 request by U.S. Department of Energy Economic Regulatory Administration, Volume 1, April.
Excludes liaison members.

ECAR

ELECTRIC POWER DEMAND

MARCH 1979 EXHIBIT II-3

ECAR
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

Representative Utilities or Power Groups	RESIDENTIAL 1972	1973	1974	1975	1976	1977	COMMERCIAL 1972	1973	1974	1975	1976	1977
East Central Area Reliability Council	-	-	-	-	-	7 0	-	-	-	-	-	6.0
American Electric Power System	7.5	8.5	4.2	5.3	7.3	5.6	7.2	8.4	0.9	6.7	5.6	5.5
Allegheny Power System	-	7.8	2.9	6.2	4.1	7.6	-	9.2	(0.5)	6.7	4.6	6.3
Central Area Power Coordination Group	-	6.1	1.4	3.9	2 6	-	-	7.1	(1 0)	4.0	3.4	-
The Cincinnati Gas and Electric Company	-	8.7	1.8	11.0	2.5	12.3	-	9.8	0.5	4.2	4.3	6.4
Columbus and Southern Ohio Electric Company	-	10 4	2 6	5 9	1.4	14.4	-	11.7	0.8	4.7	3.7	14.3
The Dayton Power and Light Company	-	8.0	3.8	5.7	2.4	-	-	6.6	(0.9)	4.4	3.7	-

Representative Utilities or Power Groups	INDUSTRIAL 1972	1973	1974	1975	1976	1977	TOTAL 1972	1973	1974	1975	1976	1977
East Central Area Reliability Council	-	-	-	-	-	6.0	-	-	-	-	-	6 6
American Electric Power System	4.8	8.9	0.2	(15.0)	6.5	9 3	7.0	7 6	1 4	(6.2)	6.5	(3.6)
Allegheny Power System	-	7.8	0.5	12.2	18.2	4 8	-	8.9	1.0	0.9	11.4	4.2
Central Area Power Coordination Group	-	13 3	(1 8)	10.2	8.1	-	-	9.7	(0 7)	(3.1)	5.4	-
The Cincinnati Gas and Electric Company	-	6.2	(0 9)	19.1)	9.1	4.5	-	7.7	0 7	1 9	5 1	8.0
Columbus and Southern Ohio Electric Company	-	7 2	(3.0)	(5.4)	3.6	12.8	-	9 8	0.4	2.5	3.3	14.4
The Dayton Power and Light Company	-	10.5	(6.0)	(5.6)	14.7	-	-	8.3	0 2	2.1	6.3	-

Note: Figures in parenthesis indicate negative values.

Sources:
1. ECAR (1978) "Coordinated Regional Bulk Power Supply Programs," Volume II
2. American Electric Power (1978) "1977 Annual Report".
3. Allegheny Power System (1978) "1977 Annual Report."
4. The Toledo Edison Company "Ten-Year Forecast for Electric Generation and Transmission Facilities", submitted to the Ohio Power Siting Commission, April 15, 1977.
5. Cincinnati Gas and Electric Company (1978) "Annual Report 1977".
6. Columbus and Southern Ohio Electric Company (1978) "1977 Annual Report"
7. The Dayton Power and Light Company, "Ten-Year Forecast Report to the Ohio Power Siting Commission", May 15, 1977

ECAR
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION
MARCH, 1979
EXHIBIT II-4

ECAR
SYSTEM LOAD VARIATIONS 1/
1977

Representative Utilities or Power Groups	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor
ALLEGHENY POWER SYSTEM										
Monongahela Power Company	86.7	80.4	86.8	77.8	94.9	82.4	1,263 2/	Jan 11	7,716	69.7
Potomac Edison Company										
West Pennsylvania Power Company	86.2	79.2	85.7	77.3	99.3	79.7	2,369	Jan 12	14,194	68.4
AMERICAN ELECTRIC POWER SYSTEM										
Appalachian Power Company	-	-	-	-	-	-	-	-	-	-
Indiana and Michigan Electric Company	80.2	71.5	79.3	74.2	94.3	80.0	2,919	Jan 17	14,728	57.6
Kentucky Power Company	-	-	-	-	-	-	-	-	-	-
Ohio Power Company	90.9	83.5	91.4	83.3	100.0	87.8	4,452	Dec 5	30,154	77.3
CENTRAL AREA POWER COORDINATION GROUP										
Cleveland Electric Illuminating Company	80.2	75.5	91.2	74.7	86.3	80.6	3,381	Jul 7	19,098	64.5
Duquesne Light Company	81.4	77.0	91.4	75.8	88.1	80.5	2,371	Jul 21	13,680	65.9
Ohio Edison System	82.4	75.0	91.6	74.7	93.5	78.9	3,620	Jul 20	20,607	65.0
Pennsylvania Power Company										
Toledo Edison Company	82.9	75.5	90.5	76.5	92.5	79.4	1,393	Jul 15	7,847	64.3
CINCINNATI COLUMBUS DAYTON GROUP	70.3	73.7	84.3	73.1	91.3	76.7	6.682		33,663	57.5
Cincinnati Gas and Electric Company	66.6	75.8	84.8	74.1	86.7	77.4	2,841	Jul 20	14,385	57.8
Columbus and Southern Ohio Electric Company	69.8	72.5	84.1	72.2	89.1	76.7	1,889	Jul 20	9,032	54.6
Dayton Power and Light Company	76.4	72.0	84.0	72.6	100	75.9	1,952	Dec 6	10,246	59.9
KENTUCKY - INDIANA	75.3	79.6	88.3	77.1	90.5	82.0	14,084		88,842	65.5
East Kentucky Power Cooperative	63.4	69.5	63.0	66.5	98.6	71.1	798	Dec 6	3,300	47.3
Indianapolis Power and Light Company	69.5	70.8	83.3	73.0	84.7	79.1	1,802	Jul 15	8,991	57.0
Kentucky Utilities Company	71.1	70.7	94.0	68.9	96.2	76.8	1,797	Jan 18	9.693	61.2
Louisville Gas and Electric Company	58.5	75.4	92.4	69.6	72.9	77.5	1,705	Jul 15	8,030	53.8
Northern Indiana Public Service Company	82.8	84.7	94.7	78.4	87.9	86.6	2,204	Jul 15	13,787	71.4
Ohio Valley Electric Corporation	96.0	98.5	96.2	99.7	99.9	98.8	1,982	Oct 22	16,725	96.3
Public Service Company of Indiana	77.9	75.0	82.7	76.0	98.1	78.0	3,127	Jul 15	17,341	63.3
Southern Indiana Gas and Electric Company	60.5	72.8	87.9	66.6	71.6	77.2	669.2	Jul 18	2,975	50.7
MICHIGAN ELECTRIC COORDINATED SYSTEM	76.4	76.4	86.0	77.0	86.1	79.4	11,852.1		65,813	63.4
Consumers Power Company	82.8	74.9	89.9	76.8	93.9	79.3	4,471.1	Jul 20	26,567	67.8
Detroit Edison Company	72.6	77.5	82.3	77.2	81.4	79.4	7,381	Jul 15	39,246	60.7

1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12

2/ Non-coincident peaks

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

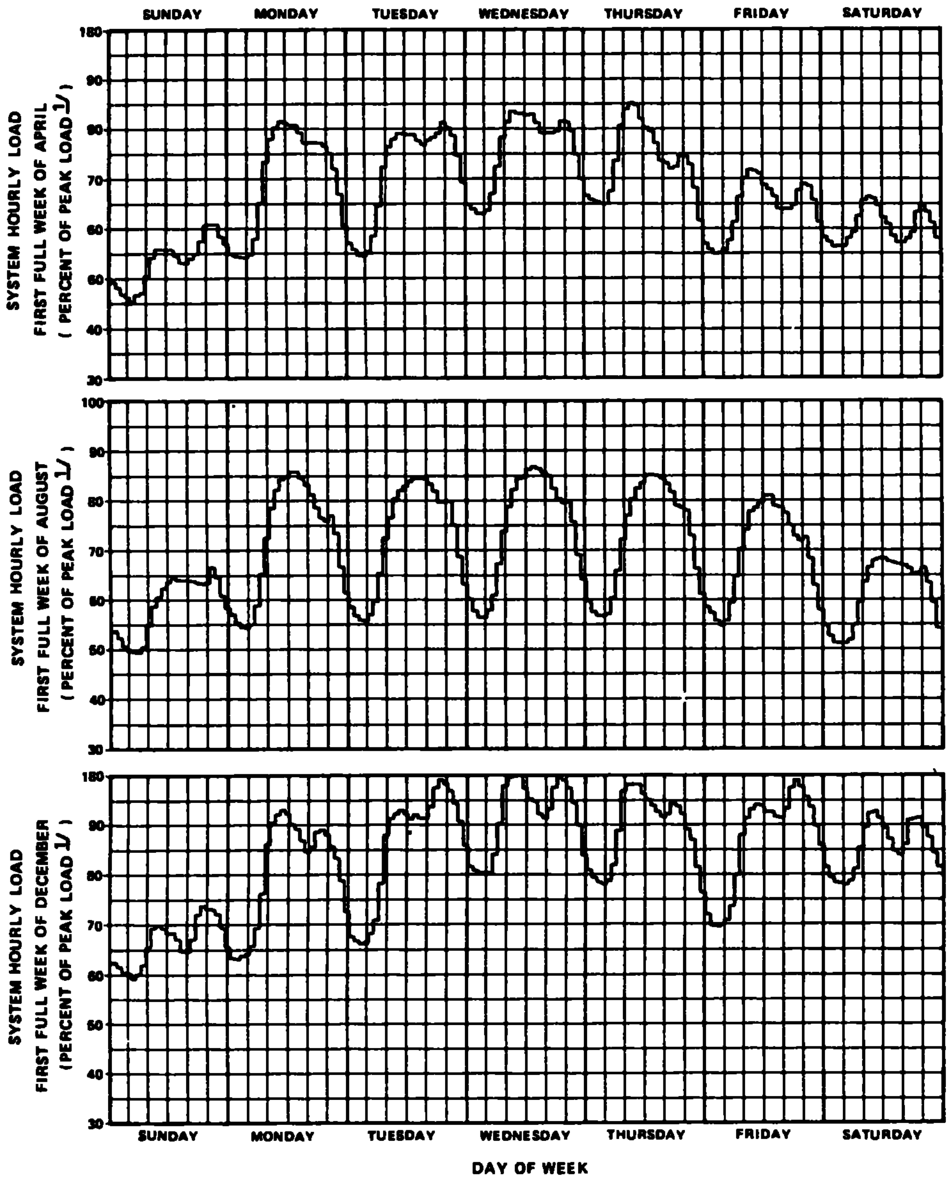
DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

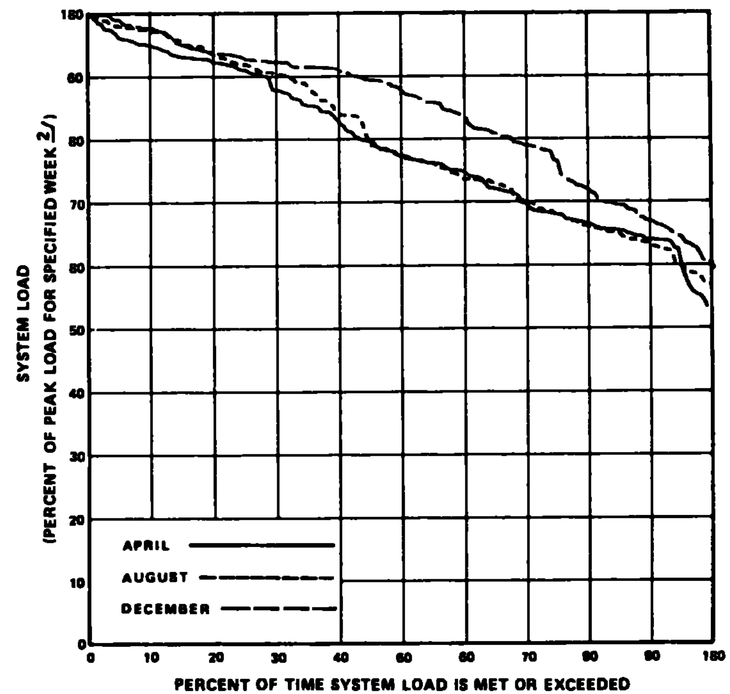
THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

ECAR

SYSTEM LOAD VARIATIONS, 1977

CONTRACT NO. [illegible]
DATE MARCH, 1979
EXHIBIT II-5





NOTES.

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

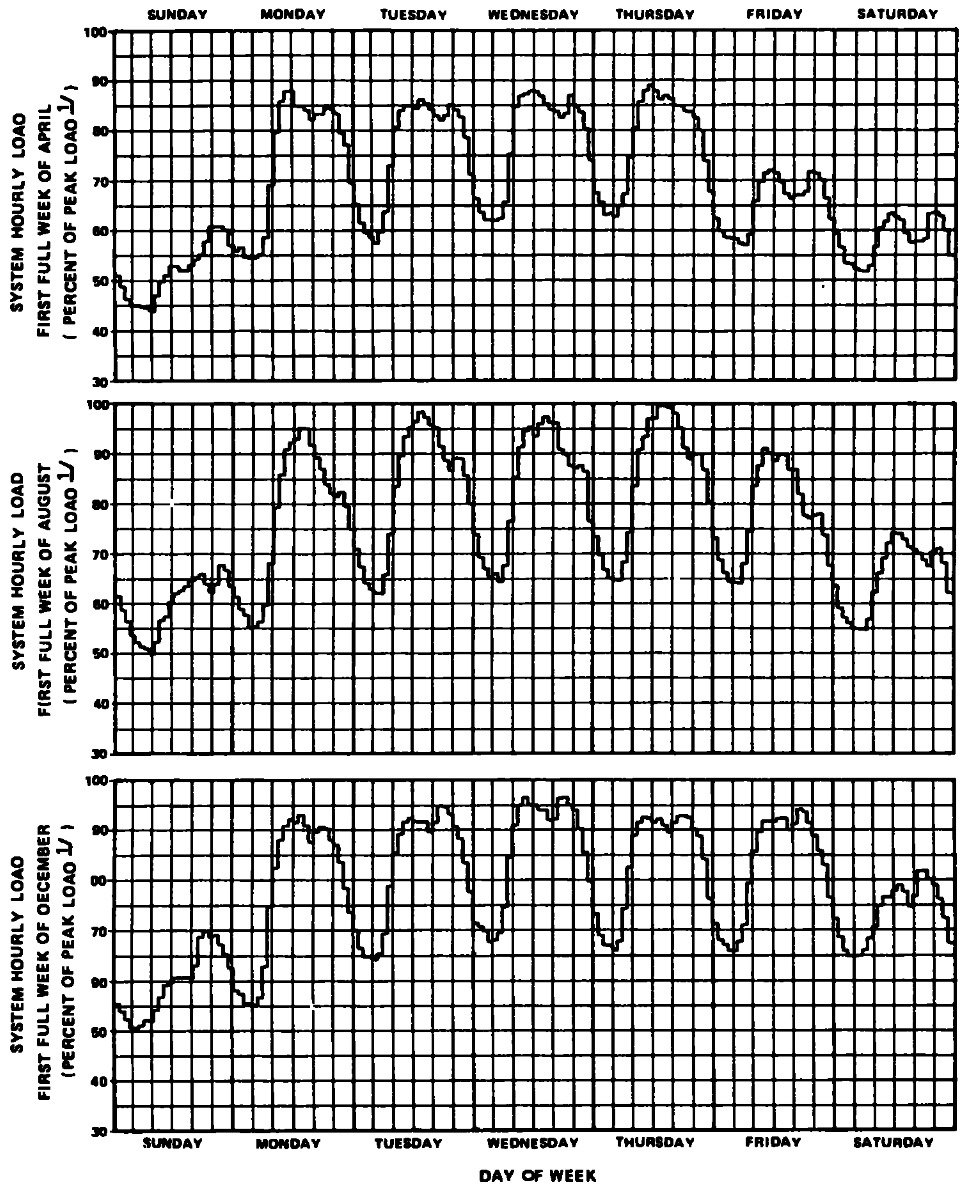
DEPARTMENT OF THE ARMY

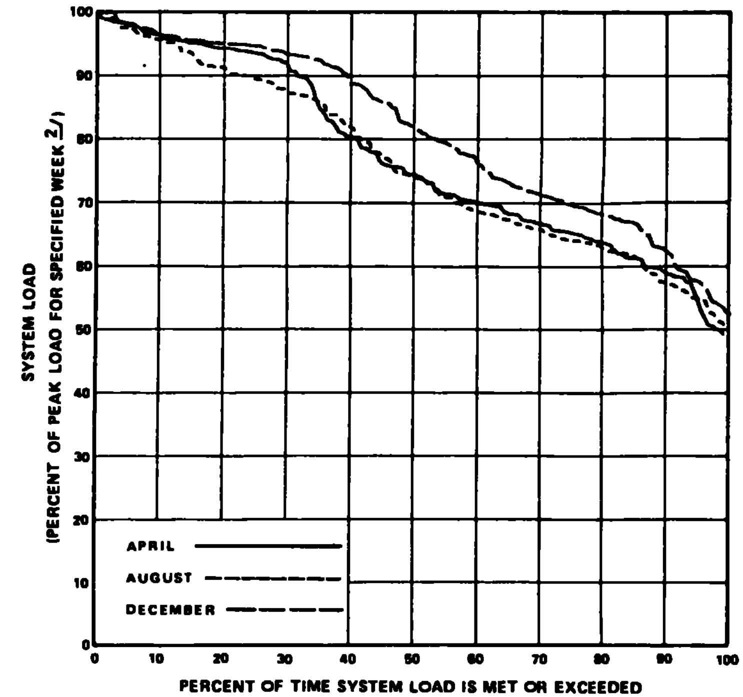
LOAD CURVES

REGION ECAR
SUB-REGION AEP
UTILITY. AEP
SHEET 1 OF 7

DATE MARCH, 1979

EXHIBIT II-6





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION ECAR

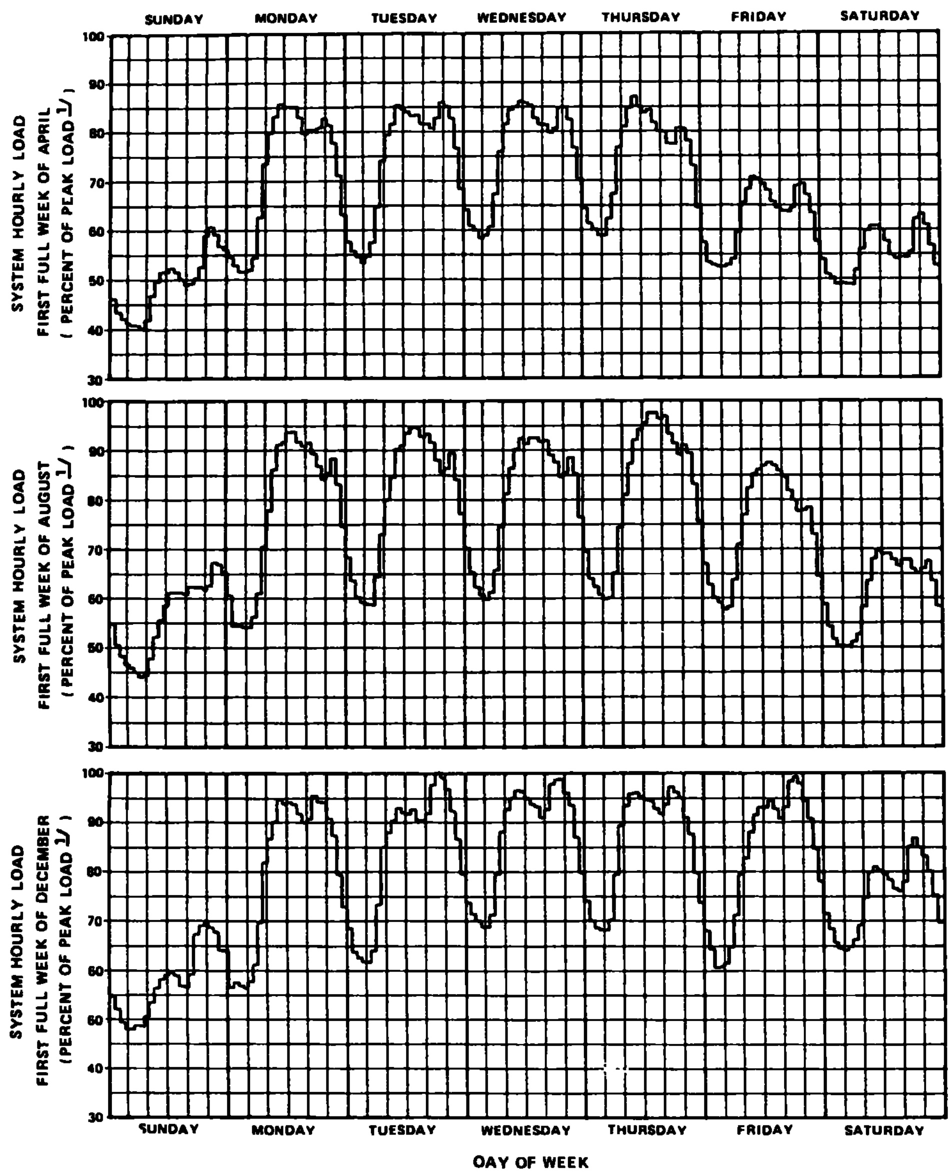
SUB-REGION: CAPCO

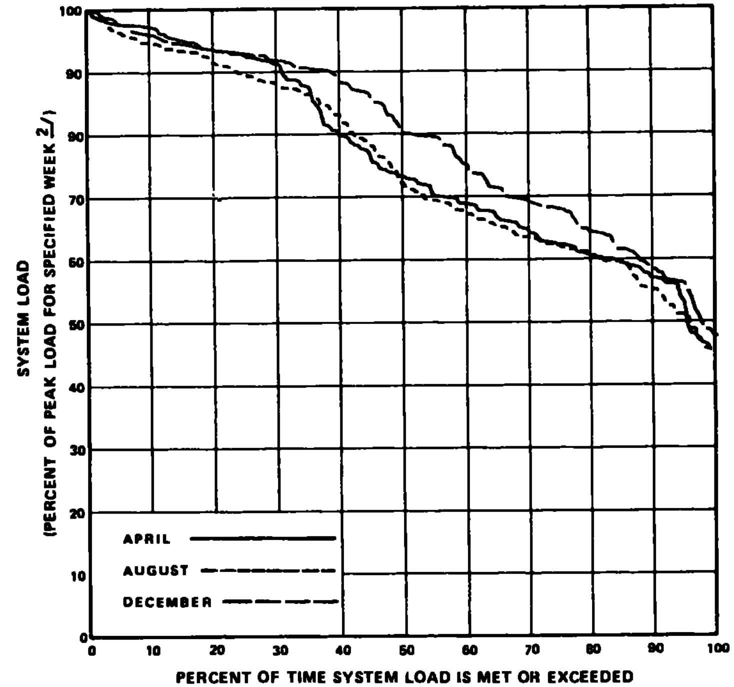
UTILITY DLCO

SHEET 2 OF 7

MARCH, 1979

II-6





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION ECAR

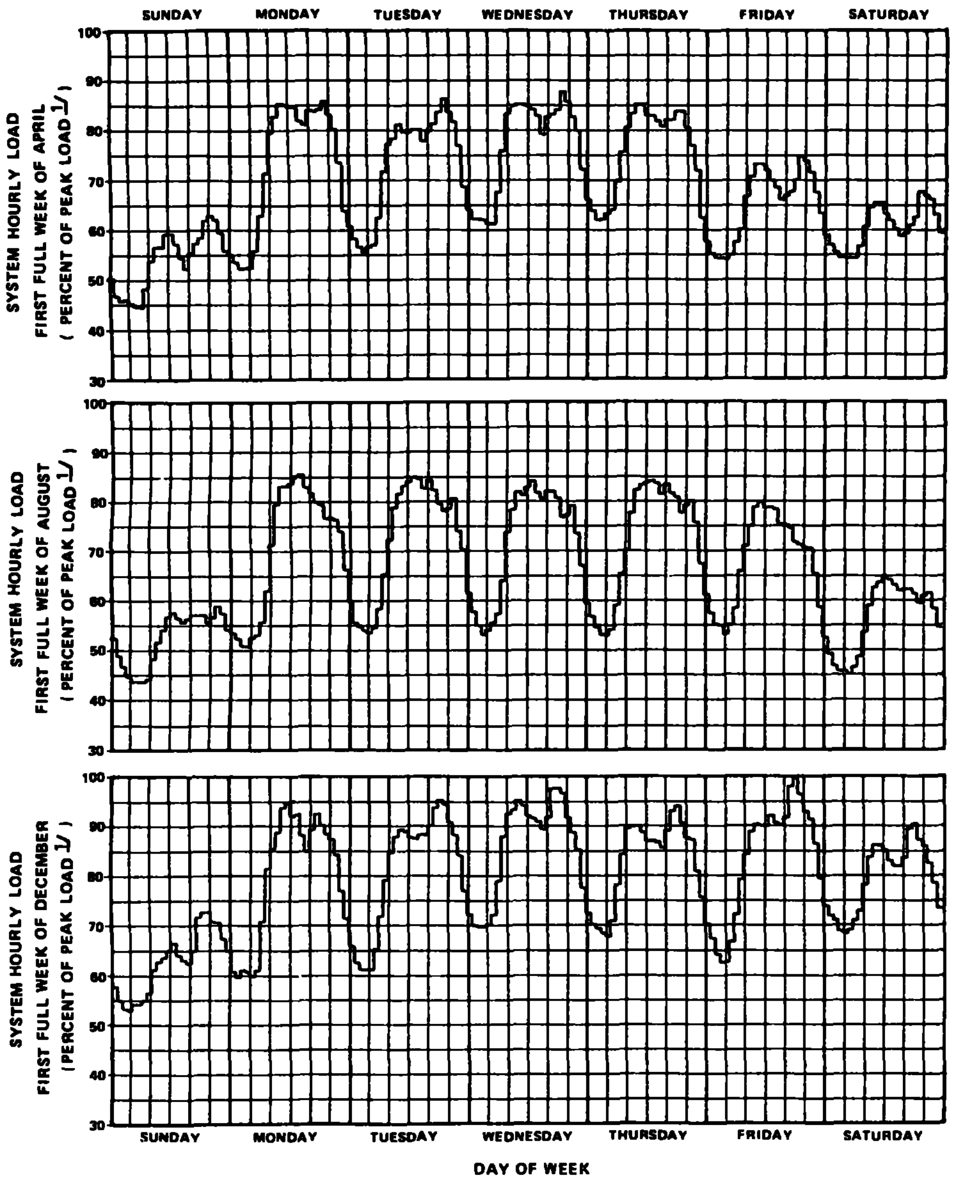
SUB-REGION CAPCO

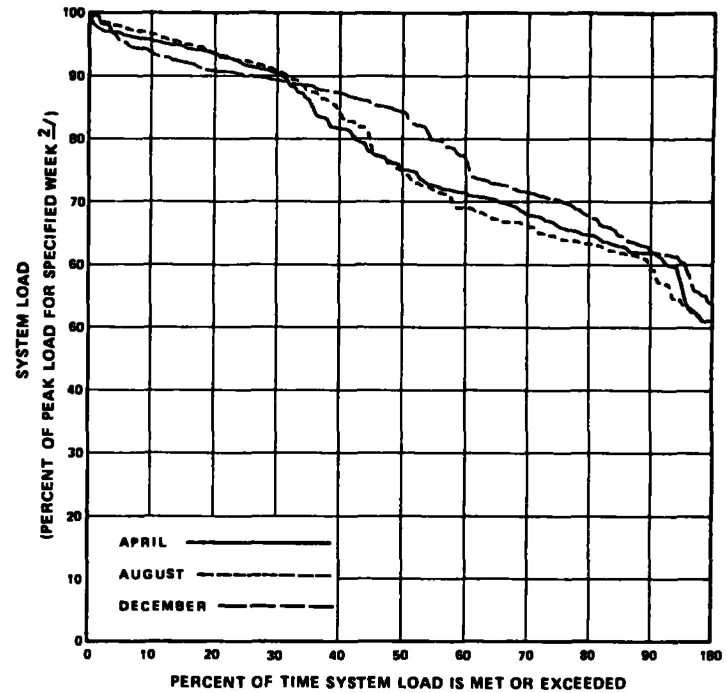
UTILITY OE

SHEET 3 OF 7

MARCH 1979

EXHIBIT II-6





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SOURCE.

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

ENGINEERING COMPANY	DEPARTMENT OF THE ARMY

LOAD CURVES

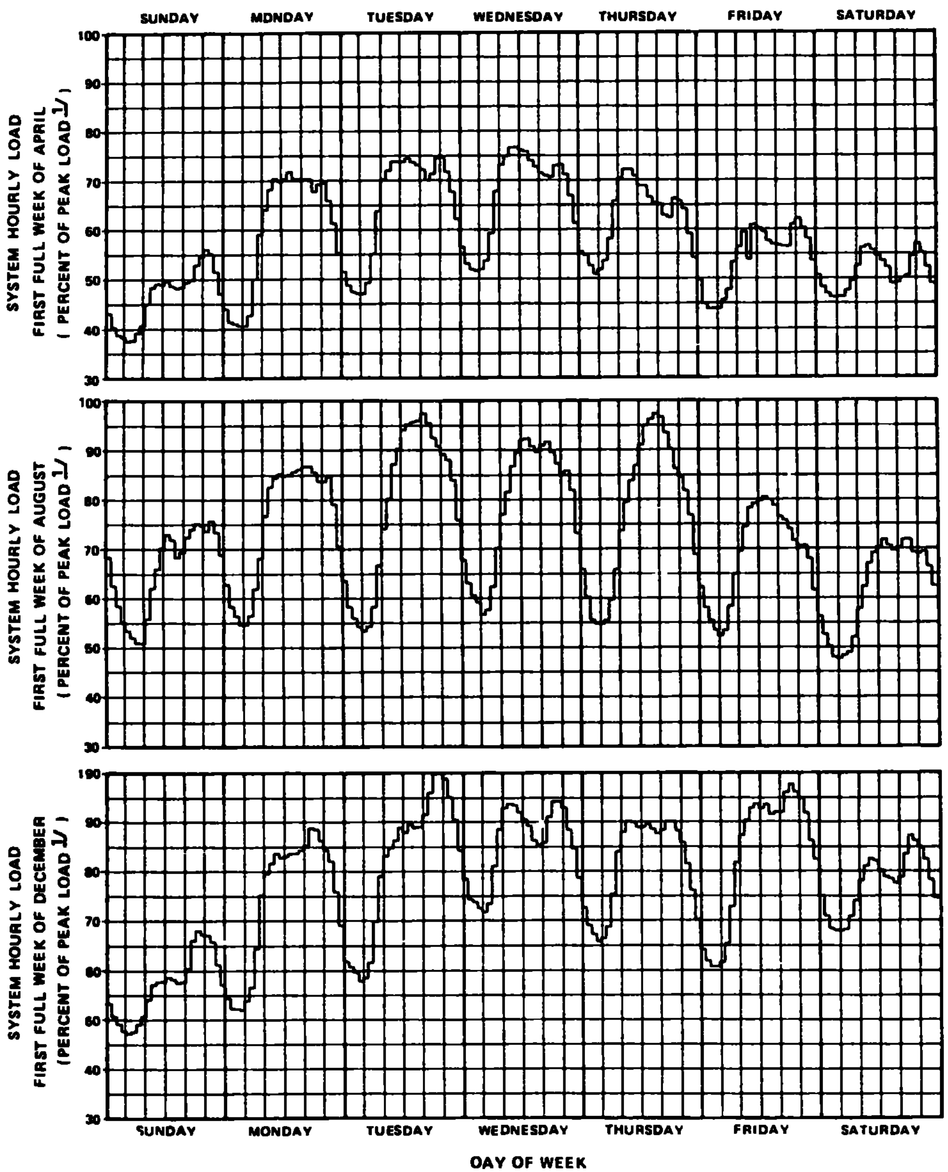
REGION ECAR

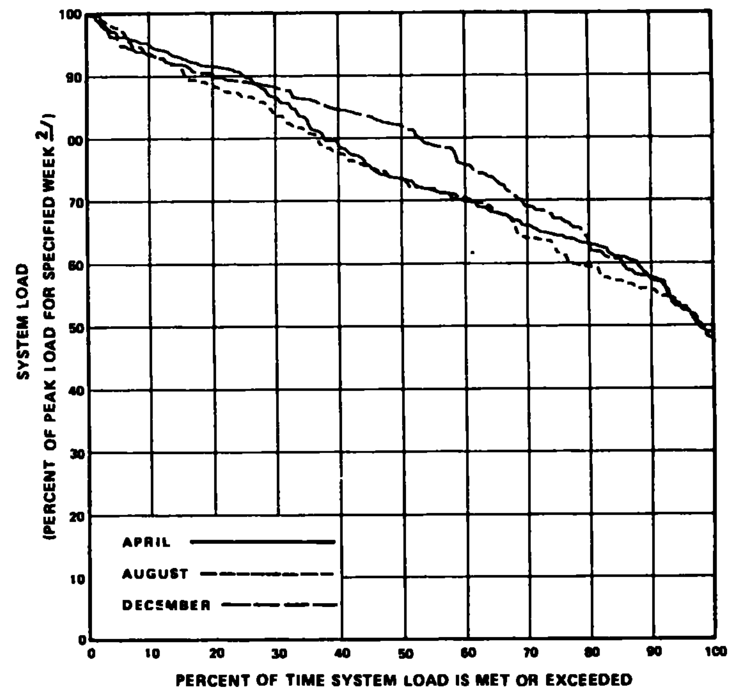
SUB–REGION APS

UTILITY WEPP

SHEET 4 OF 7

DATE MARCH, 1979	EXHIBIT II–6





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

DEPARTMENT OF THE ARMY

CORPS OF ENGINEERS

LOAD CURVES

REGION ECAR

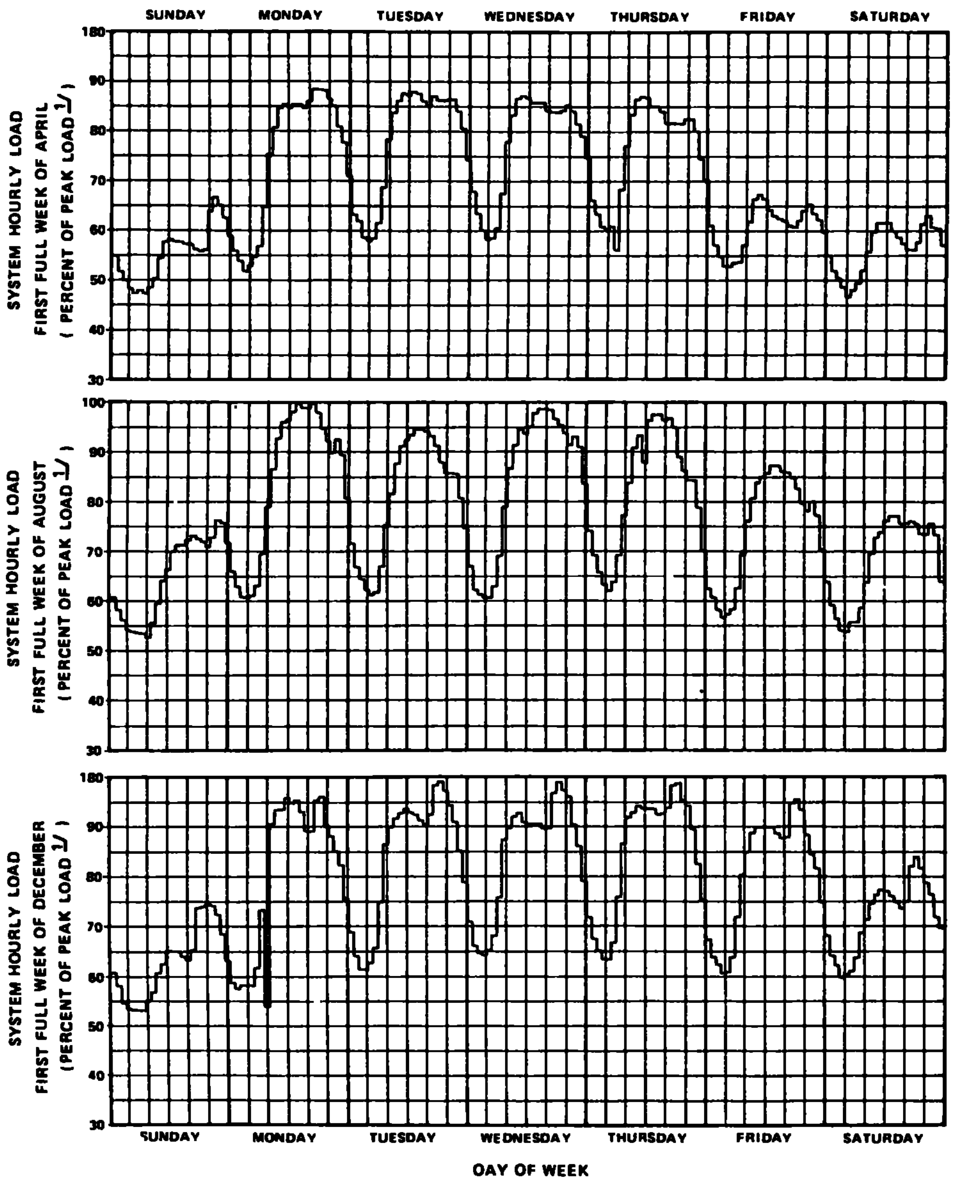
SUB-REGION CCD

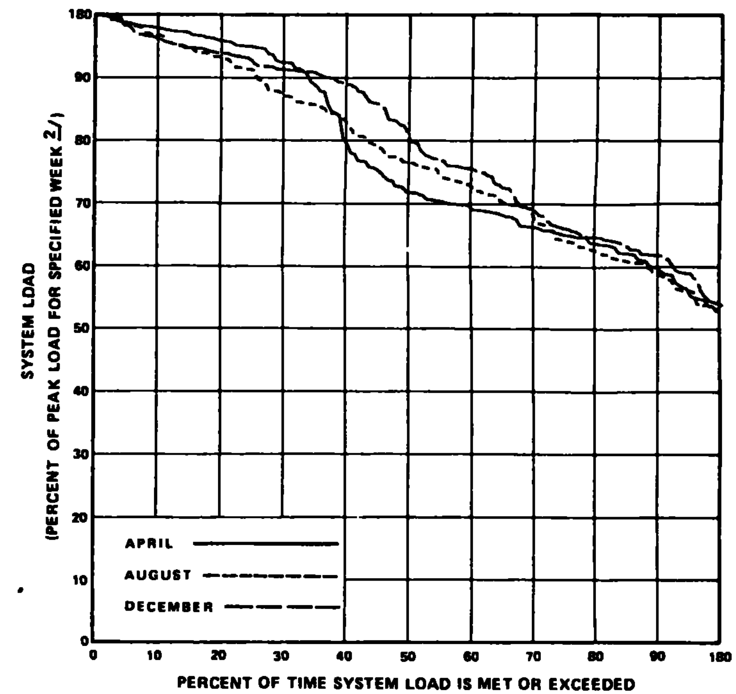
UTILITY CG & E

SHEET 5 OF 7

MARCH, 1979

EXHIBIT II-6





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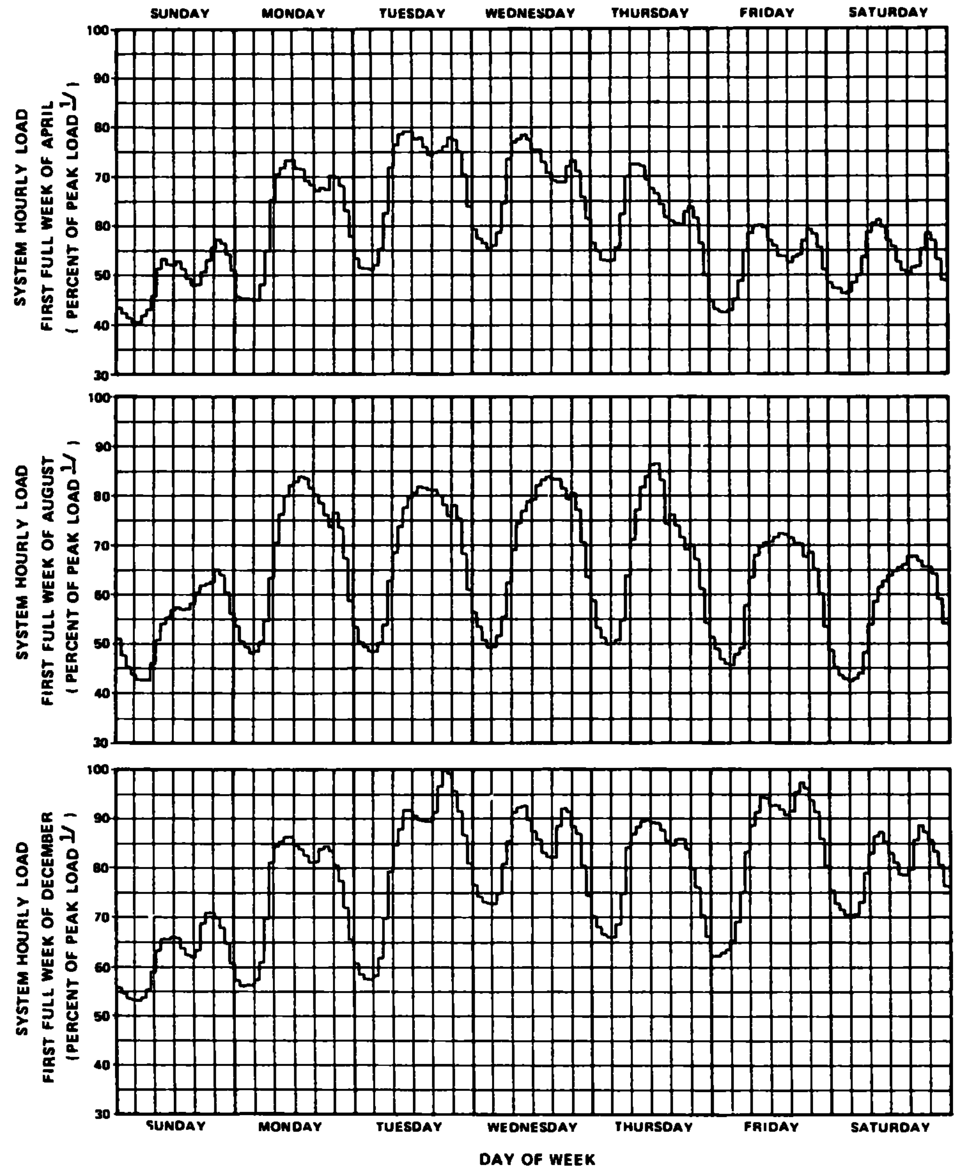
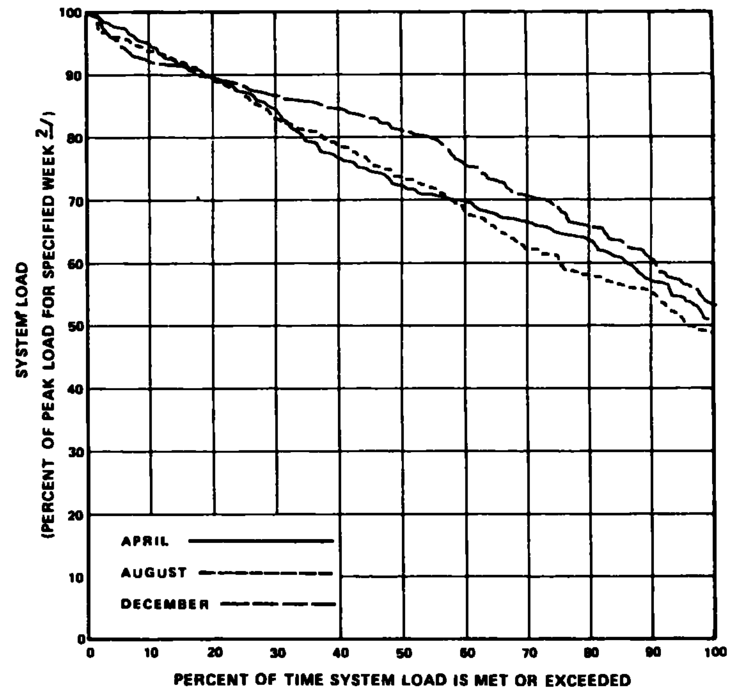
SOURCE

DATA OBTAINED FROM FERC FORM NO. 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES	
REGION	ECAR
SUB-REGION	MECS
UTILITY	DECO
SHEET 6 OF 7	
DATE MARCH, 1979	EXHIBIT II-6





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION ECAR
SUB-REGION KY-IND
UTILITY PSI
SHEET 7 OF 7

MARCH 1979

EXHIBIT II-6

ECAR
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Allegheny Power	MW	-	-	5871	486	-	62	-	-	-	-	1.0	-	6429
System	%	-	-	91.3	7.6	-	1.0	-	-	-	-	0.1	-	100.0
American Electric	MW	1050	-	14570	240	-	543	140	-	18	-	-	-	16561
Power System	%	6.3	-	88.0	1.4	-	3.4	0.8	-	0.1	-	-	-	100.0
Central Area Power	MW	1222	-	11528	770	568	-	365	-	410	-	31	-	14894
Coordination Group	%	8.2	-	77.4	5.2	3.8	-	2.4	-	2.8	-	0.2	-	100.0
Cincinnati Columbus	MW	-	-	6980	278	-	-	-	72	910	-	106	110 1/	8456
Dayton Group	%	-	-	82.5	3.3	-	-	-	0.9	10.8	-	1.2	1.3	100.0
Kentucky - Indiana	MW	-	71	16264	491	-	124	-	127	507	-	33	-	17617
	%	-	0.4	92.3	2.8	-	0.7	-	0.7	2.9	-	0.2	-	100.0
Michigan Electric	MW	791	21	8460	3250	-	134	1872	626	408	-	152	-	15714 2/
Coordinated System	%	5.0	0.1	53.8	20.7	-	0.9	11.9	4.0	2.6	-	1.0	-	100.0
Liaison Members	MW	-	8	3719	107	25	35	-	-	199	54	69	-	4215 2/
	%	-	0.2	88.3	2.5	0.6	0.8	-	-	4.7	1.3	1.6	-	100.0
ECAR Total	MW	3063	100	67392	5622	593	898	2377	825	2452	54	390	120	83886
	%	3.7	0.1	80.3	6.7	0.7	1.1	2.8	1.0	2.9	0.1	0.5	0.1	100.0

Source: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

1/ Jet Engine - Kerosene
2/ Total Capability has been computed from the addition of the individual capability given for each unit in Item 2-A (found in the above source). No allowance was made for smoke, boiler, or customer limitation.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

ECAR
EXISTING GENERATING CAPABILITY

DATE MARCH, 1979
EXHIBIT II-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND MAAC REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MAAC**	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT III-1

MAAC - REPORTING UTILITIES

Letter Code

Members of MAAC:

ATCE	Atlantic City Electric Company
BAGE	Baltimore Gas & Electric Company
DEPL	Delmarva Power & Light Company
JECP	Jersey Central Power & Light Company 1/
MEEC	Metropolitan Edison Company 1/
PEEC	Pennsylvania Electric Company 1/
PEPL	Pennsylvania Power & Light Company
PHEC	Philadelphia Electric Company
PEOP	Potomac Electric Power Company
PSEG	Public Service Electric and Gas Company
UNGI	UGI Corporation

Associates of MAAC:

ALEC	Allegheny Electric Cooperative (representing the Pennsylvania and New Jersey Cooperatives)
EAUC	The Easton Utilities Commission (representing the Maryland Municipals)
VINE	The City of Vineland Electric Utility (representing the New Jersey Municipals)

1/ Subsidiaries of the General Public Utilities Corporation

Source: "MAAC system plans report" MAAC response to FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MAAC** **LIST OF UTILITIES**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT III-2

MAAC

ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate-% 1 yr	Annual Energy: Average Annual Growth Rate-% 5 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-% 1 yr	Peak Demand: Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
1960	63.0	-	-	12.0	-	-	59.6 1/
1965	89.0	-	7.2	16.5	-	6.6	61.6
1970	129.4	-	7.8	24.1	-	7.9	61.2
1973	154.1	-	-	30.7	-	-	57.4
1974	152.7	(0.9)	-	28.2	(7.8)	-	61.7
1975	153.3	0.4	3.4	28.9	2.3	3.7	60.6
1976	158.5	3.4		29.4	1.8		61.3 1/
1977	164.1	3.5	-	32.3	9.7	-	58.0

1/ Load Factor was computed using 8784 hours to reflect leap year.

Source:
1. Federal Power Commission, "The 1970 National Power Survey" Part II, Washington D.C, 1970.
2. Department of Energy, "Energy Information Report on annual report of monthly comparisons of peak demands and energy for load - 1973 to 1977", Washington D.C, May 1978.
3. "MAAC System Plans Report" FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAAC

ELECTRIC POWER DEMAND

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH, 1979

EXHIBIT III-3

MAAC
ANNUAL GROWTH RATES CF FNERGY CONSUMPTION BY CONSUMER CATAGORIES
(Percentage)

Representative Utilities	RESIDENTIAL 1971	1972	1973	1974	1975	1976	1977	COMMERCIAL 1971	1972	1973	1974	1975	1976	1977
Atlantic City Electric Company	6 8	7.2	9 0	(0.9)	3 0	6 8	7.3	8.4	11.7	14.2	(3 9)	3.6	3 4	6 2
Baltimore Gas and Electric Company	-	-	-	(3 2)	4 4	4 8	7.0	-	-	-	(2 9)	4 2	3 3	3 7
Delmarva Power & Light Company	7.8	6 0	11.3	(2.0)	4 6	6.9	7.7	9.0	11.6	10.8	(4 2)	4.3	3 9	5.9
General Public Utilities Corporation	-	-	-	0.5	3.2	5.5	3.3	-	-	-	(1 2)	6.6	6.9	5.4
Pennsylvania Power & Light Company	-	-	-	2.7	5.0	6.6	3.7	-	-	-	0 3	7.0	6.5	6.9
Philadelphia Electric Company	-	-	9.3	(4.5)	3.7	2.2	6 9	-	-	6 4	(3 9)	2.6	5.0	2.5
Potomac Electric Power Company	-	-	-	(6.4)	2 9	2.5	3 8	-	-	-	17 3)	5.9	3.5	(7.2)
Public Service Electric and Gas Company	-	-	8 2	(6.2)	1 2	1.4	0 8	-	-	7 6	(2 5)	3 5	5 8	2 5

Representative Utilities	INDUSTRIAL 1971	1972	1973	1974	1975	1976	1977	TOTAL 1971	1972	1973	1974	1975	1976	1977
Atlantic City Electric Company	3 8	7 2	5.4	1.6	(8.8)	10.3	6.7	6.4	8 5	9.6	1.2	0.1	6.6	6 8
Baltimore Gas and Electric Company	-	-	-	(1.8)	(6.3)	9.1	3 6	-	-	-	(2.4)	10.9)	6.5	4 8
Delmarva Power & Light Company	(0 5)	7 1	4.2	(2.1)	113.0)	5.5	0.8	3.9	7.8	7.8	(2 6)	(3.5)	5 5	4 3
General Public Utilities Corporation	-	-	-	(3.4)	(9.7)	6.4	3.6	-	-	-	(1 6)	(1.5I	6 2	3.9
Pennsylvania Power & Light Company	-	-	-	4.2	(2.1)	6 6	2.9	-	-	-	2.7	2.6	6 6	4.2
Philadelphia Electric Company	-	-	6.7	(2 2)	(3.8)	4.3	1.7	-	-	7.4	(3.1)	(0.9)	3.7	3.4
Potomac Electric Power Company	-	-	-	(12.5)	2.6	2 2	31.8	-	-	-	(0.3)	4.3	2.9	4 3
Public Service Electric and Gas Company	-	-	4.0	(5.0)	(9.8)	3 3	1.5	-	-	6.1	(4.4)	(2.6)	3.6	1.6

Source: The 1977 annual reports for each respective utility.

MAAC
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION
MARCH 1979
III - 4

MAAC
SYSTEM LOAD VARIATIONS[1/]

	First Week of April		First Week of August		First Week of December		Annual			
	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand MW	Date	Net Energy GWh	Load Factor %
PJMI[2/]	68.7	77.6	92.5	75.5	81.8	78.3	32,180	July 21	163,376.8	58.0

1/ Computations based on information provided in schedules 14 and 15 of the 1977 FERC Form 12.

2/ Since PJMI submits a Form 12 to FERC as a system as well as on an individual utility basis, the system information is recorded for simplicity.

[illegible] ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

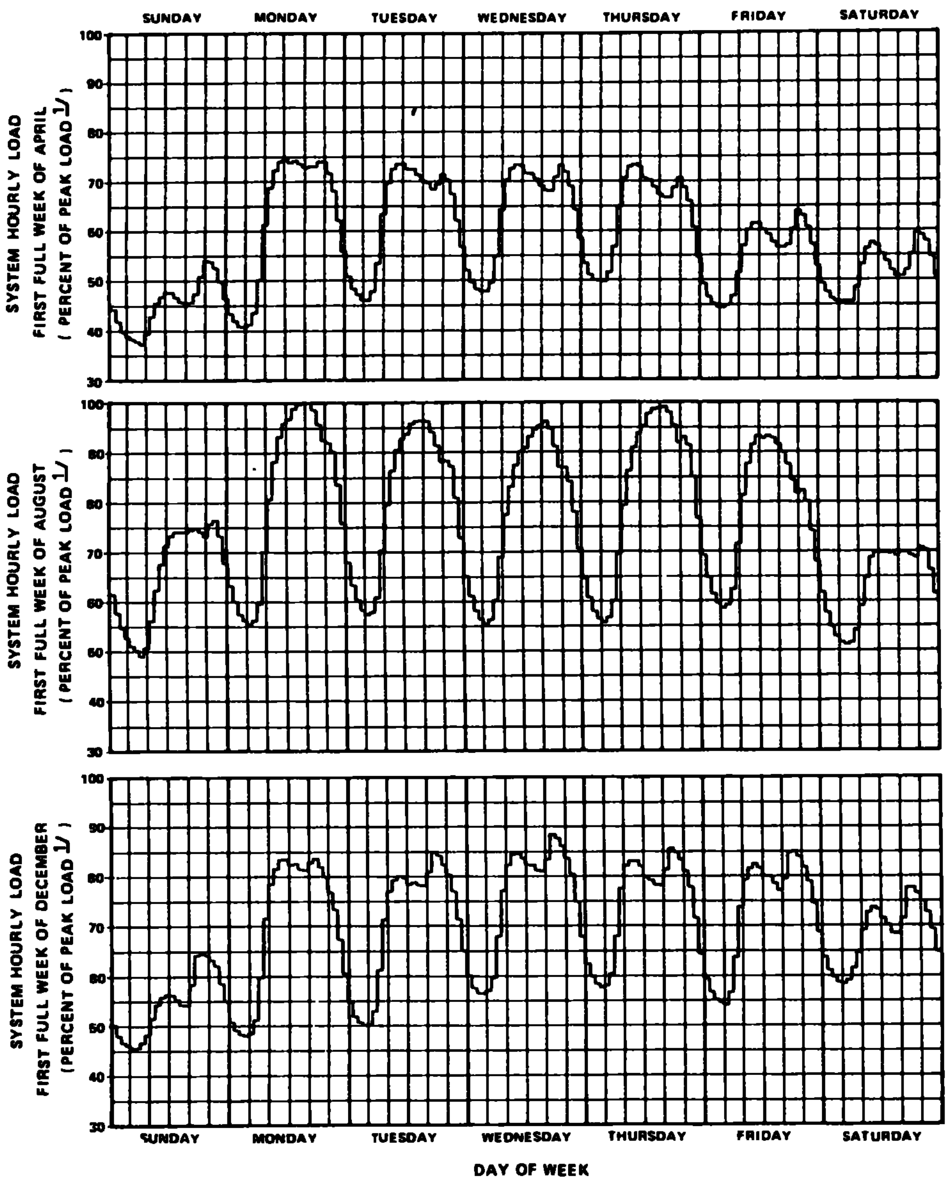
DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

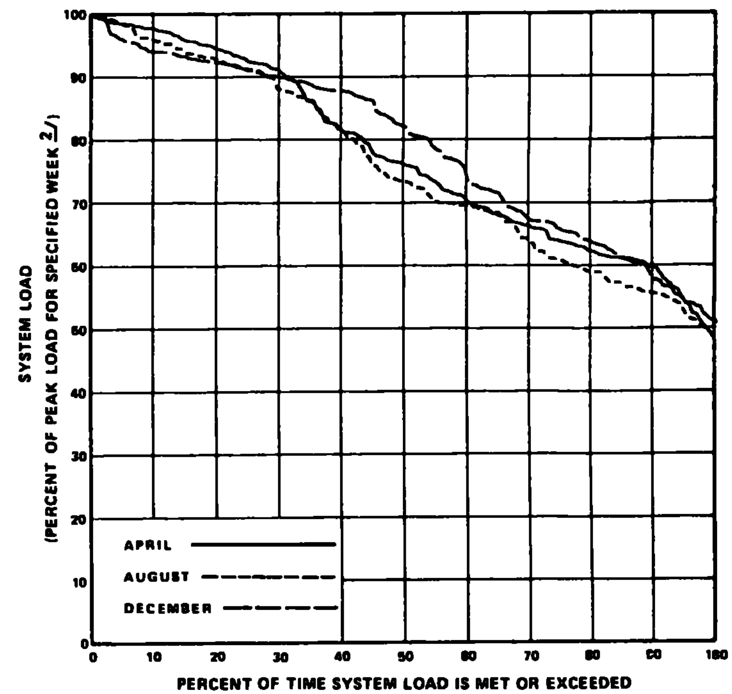
THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAAC
SYSTEM LOAD VARIATIONS, 1977

DATE MARCH 1979

EXHIBIT III-5





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

HARZA ENGINEERING COMPANY	DEPARTMENT OF THE ARMY

LOAD CURVES

REGION: MAAC
SUB-REGION: MAAC
UTILITY PJM

DATE MARCH, 1979	EXHIBIT III-6

MAAC
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Public Service	MW	1,352	-	2,010	3,156	140	-	165	63	3,203	-	5	-	10,094
Electric & Gas	%	13.4	-	19.9	31.3	1.4	-	1.6	0.6	31.7	-	0.0	-	100.0
Philadelphia	MW	1,352	-	1,526	2,151	-	512	880	21	2,032	-	30	-	8,504
Electric Co.	%	15.9	-	17.9	25.3	-	6.0	10.4	0.2	23.9	-	0.4	-	100.0
Atlantic City	MW	237	-	417	524	-	-	-	-	456	-	9	-	1,643
Electric Company	%	14.4	-	25.4	31.9	-	-	-	-	27.8	-	0.5	-	100.0
Delmarva Power &	MW	238	-	471	1,286	-	-	-	-	213	-	59	-	2,267
Light Company	%	10.5	-	20.8	56.7	-	-	-	-	9.4	-	2.6	-	100.0
Pennsylvania Power	MW	-	-	4,145	1,640	-	222	-	-	517	-	59	-	2,267
& Light Company	%	-	-	63.3	25.1	-	3.4	-	-	7.9	-	0.3	-	100.0
UGI Corporation	MW	-	-	115	-	-	-	-	-	-	-	-	-	115
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Baltimore Gas &	MW	1,640	-	858	1,837	-	152	-	136	392	-	3	264 1/	5,282
Electric Co.	%	31.1	-	16.2	34.8	-	2.9	-	2.6	7.4	-	0.0	5.0	100.0
General Public	MW	1,468	-	3,041	518	367	61	241	55	1,422	-	17	-	7,190
Utilities	%	20.4	-	42.3	7.2	5.1	0.8	3.4	0.8	19.8	-	0.2	-	100.0
Potomac Electric	MW	-	-	2,944	1,511	-	-	-	-	686	-	1	-	5,142
Power Company	%	-	-	57.3	29.4	-	-	-	-	13.3	-	0.1	-	100.0
MAAC(PJMI)Total	MW	6,287	-	15,527	12,623	507	947	1,286	275	8,921	-	146	264	46,783
	%	13.4	-	33.2	27.0	1.1	2.0	2.7	0.6	19.1	-	0.3	0.6	100.0

1/ Jet Engine - Kerosene

SOURCE: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
DEPARTMENT OF THE ARMY

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAAC

EXISTING GENERATING CAPABILITY

DATE MARCH, 1979

EXHIBIT III-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-L
AND MAIN REGIONAL REPORT

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAIN

CONTRACT NO DACW72 – 78 – C – 0013

DATE MARCH, 1979

EXHIBIT IV–1

MAIN - REPORTING UTILITIES

Letter Code	Sub-Region
CECO	COMMONWEALTH EDISON
ILL-MO	ILLINOIS-MISSOURI POOL
	Members of MAIN:
CEIP	Central Illinois Public Service Company
ILPC	Illinois Power Company
UNEC	Union Electric Company
ASEC	Associated Electric Cooperative, Inc.
CEIL	Central Illinois Light Company
SOIP	Southern Illinois Power Cooperative
SPFI	Springfield, Illinois, City Water, Light and Power Department
	Associate Members of MAIN:
WEIL	Western Illinois Power Cooperative, Inc.
	Non-Members:
COLM	City of Columbia, Missouri
WUMS	WISCONSIN-UPPER MICHIGAN SYSTEM
	Members of MAIN:
MAGE	Madison Gas and Electric Company
UPPP	Upper Peninsula Power Company
WIEP	Wisconsin Electric Power Company
WIPL	Wisconsin Power and Light Company
WIPS	Wisconsin Public Service Corporation
	Associate Members of MAIN:
	Municipal Electric Utilities of Wisconsin Association
KAUK	Kaukauna - Menasho Interconnected Systems
MANI	Manitowoc, Wisconsin, Public Utilities
MARF	Marshfield, Wisconsin, Electric and Water Department
	Non-Members:
MARQ	Marquette, Michigan, Board of Light & Power

Source: "MAIN's 1978 Reply to Appendix A-2," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAIN

LIST OF UTILITIES

CONTRACT NO DACW72-78-C-0013
DATE MARCH, 1979

EXHIBIT IV-2

MAIN

ANNUAL ENERGY, PEAK DEMAND AND LABOR FACTOR

	Calendar Year	Annual Energy 1/ Thousands of GWH	Annual Energy 1/ Average Growth 1 yr	Annual Energy 1/ Annual Rate-% 5 yr	Peak Demand 2/ Peak GW	Peak Demand 2/ Average Growth 1 yr	Peak Demand 2/ Annual Rate-% 5 yr	Annual Load Factor-%
MAIN								
	1971				24.9	-	-	
	1972				26.8	7.9	-	
	1973				29.0	8.1	-	
	1974				29.1	0.1	-	
	1975				29.6	2.0	-	
	1976				31.0	4.6	4.5	
	1977	161.1			33.4	7.8	4.5	55.1
COMMONWEALTH EDISON								
	1971				10.9	-	-	
	1972				11.8	7.4	-	
	1973				12.8	9.2	-	
	1974				12.3	(4.4)	-	
	1975				12.3	0.3	-	
	1976				12.9	4.9	3.4	
	1977	65.1			13.9	7.9	3.3	53.5
ILLINOIS-MISSOURI POOL								
	1971				7.5	-	-	
	1972				8.1	9.6	-	
	1973				8.5	4.5	-	
	1974				9.1	6.3	-	
	1975				9.1	0.3	-	
	1976				9.5	4.3	4.8	
	1977	47.9			10.2	7.1	4.5	54.1
WISCONSIN-UPPER MICHIGAN SYSTEM								
	1971				4.7	-	-	
	1972				5.0	6.0	-	
	1973				5.4	9.3	-	
	1974				5.4	(0.9)	-	
	1975				5.7	5.0	-	
	1976				5.9	4.1	4.7	
	1977	33.5			6.3	7.3	4.7	60.7

1/ MAIN's 1978 Reply to Appendix A-2 of Order No. 383-4, Docket R-362, April 1, 1978.

2/ Information obtained from MAIN in November 15, 1978 letter.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MAIN** **ELECTRIC POWER DEMAND**	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT IV-3

MAIN
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

Representative Utilities or Power Groups	Residential					Commercial					Industrial					Total				
	1973	1974	1975	1976	1977	1973	1974	1975	1976	1977	1973	1974	1975	1976	1977	1973	1974	1975	1976	1977
Commonwealth Edison	6.6	-2.4	7.2	-0.3	5.6	7.6	-2.3	3.0	4.3	4.1	9.8	-0.9	-5.9	4.4	6.8	8.1	-1.8	1.0	2.8	5.3
Illinois-Missouri Pool																				
Central Illinois Public Service Company	7.7	2.3	11.6	1.4	8.9	7.5 2/	0	10.6	6.5	6.1	3.7 4/	-0.6	4.6	8.7	5.9	5.5	0.5	7.7	5.9	6.9
Illinois Power Company	0	0.4	11.6	-0.2	11.0	-	-0.5	10.6	1.7	20.8	NA	0.8	1.2	11.4	2.0	NA	0.5	5.5	6.5	7.0
Union Electric Company	-	-2.6	15.4	-2.7	11.5	-	-0.6	5.8	4.8	8.7	NA	0.1	0.1	5.3	6.0	NA	-1.0	6.8	2.4	8.7
Wisconsin-Upper Michigan System																				
Madison Gas and Electric Company	-	-	-	-0.1	1.2	-	-	-	3.1	4.8	NA	NA	NA	-2.4	5.1	NA	NA	NA	1.5	3.4
Upper Peninsula Power Company	-	5.2	5.4	5.2	2.7	-	-0.3	14.5	-7.1	0.5	NA	6.3	-2.6	10.0	2.2	NA	3.9	5.2	3.3	8.2
Wisconsin Electric Power Company	-	-0.5	6.3	1.9	3.6	8.5	-2.3	3.8	4.8	5.3	9.9	2.6	-0.4	3.4	3.5	7.6	0.2	2.9	3.3	4.0
Wisconsin Power and Light Company	-	1.7	5.6	3.0	4.7	-	1.1	5.5	6.1	5.2	NA	-0.1	-4.0	14.4	9.5	NA	0.8	1.6	8.0	6.8
Wisconsin Public Service Corporation	1.6	0	3.2	3.1	3.0	3/					6.4	1.7	-1.7	8.6	3.2	6.1	1.6	-0.8	8.1	2.9

Source: 1977 Annual Reports of shown utilities

1/ Includes small commercial and industrial.
2/ Small light and power consumers.
3/ Commercial-inudstrial combined shown as industrial.
4/ Includes both industrial and commercial.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAIN

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

DATE MARCH, 1979

EXHIBIT IV-4

MAIN
SYSTEM LOAD VARIATIONS 1/
1977

Representative Utilities or Power Groups	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
MAIN							33,404	July	161,081	55.0
Commonwealth Edison	64.9	74.3	84.3	67.3	75.7	79.1	13,932	July 15	65,110	53.3
Illinois-Missouri Pool	59.8	76.8	83.9	71.1	73.7	80.3	9,606		45,196	53.7
Central Illinois Public Service Company	67.5	74.6	79.1	73.2	85.7	79.4	1,793	July 14	8,850	56.3
Illinois Power Company	62.0	76.9	83.0	71.9	75.6	80.0	2,846	July 15	13,935	55.9
Union Electric Company	55.7	77.6	86.2	70.1	68.3	80.8	4,967	July 19	22,411	51.5
Wisconsin-Upper Michigan System	78.6	72.3	83.7	72.6	88.7	76.8	6,331		33,407	60.2
Madison Gas and Electric Company	64.8	69.9	81.3	68.1	76.6	72.5	364	July 20	1,649	51.7
Upper Peninsula Power Company	94.4	91.7	35.8 2/	72.4	95.2	90.1	374	Jan 15	2,210	67.5
Wisconsin Electric Power Company	77.5	69.6	84.8	72.5	86.6	74.6	3,397	July 20	17,248	58.0
Wisconsin Power and Light Company	79.8	71.0	87.2	73.1	91.6	76.7	1,189	July 20	6,491	62.3
Wisconsin Public Service Corporation	80.2	75.2	94.5	73.9	94.1	79.6	1,007	July 20	5,809	65.9

1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12.
2/ Work stoppage at major industrial load center resulted in decrease in system peak from 8/8/77 thru 8/13/77.

HARZA ENGINEERING COMPANY
[illegible]

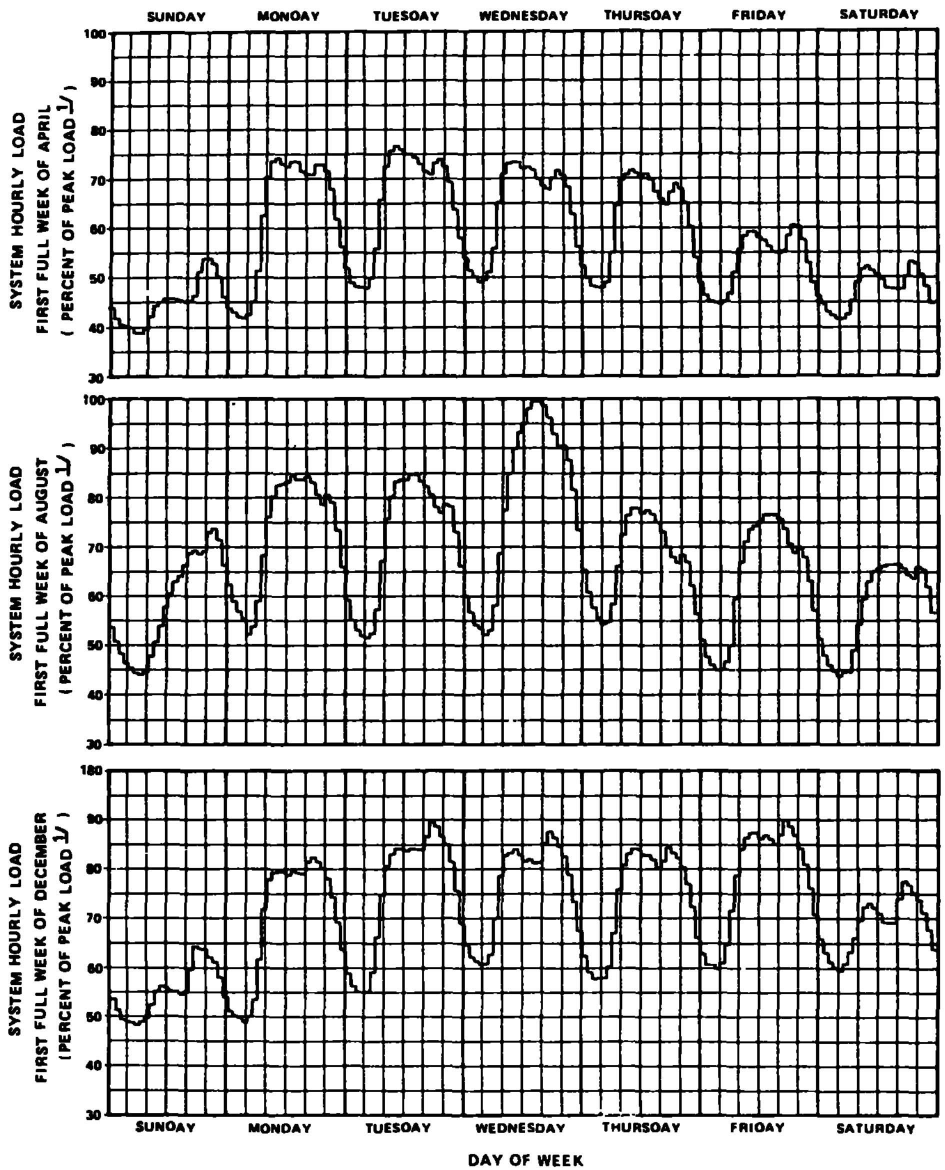
DEPARTMENT OF THE ARMY
[illegible]

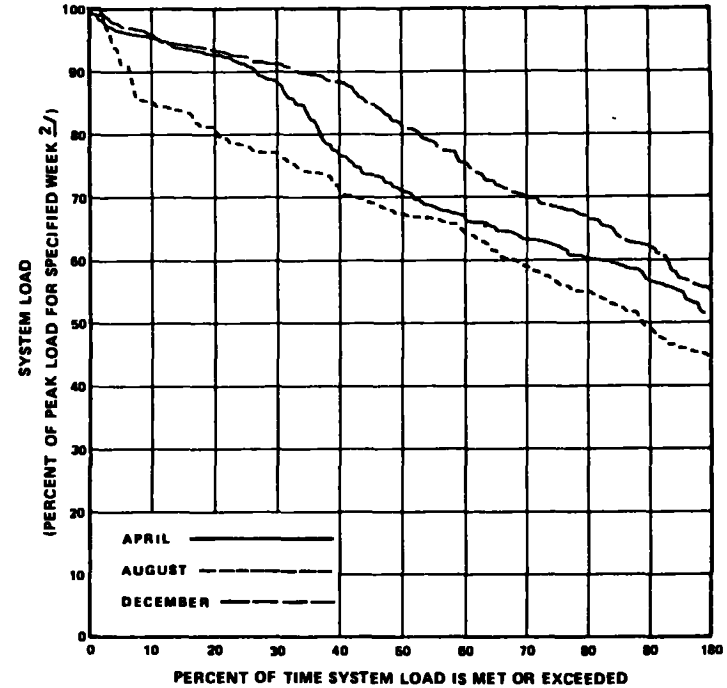
[illegible]

MAIN

SYSTEM LOAD VARIATIONS, 1977

CONTRACT NO. [illegible]
DATE MARCH, 1979
EXHIBIT IV-5





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION MAIN

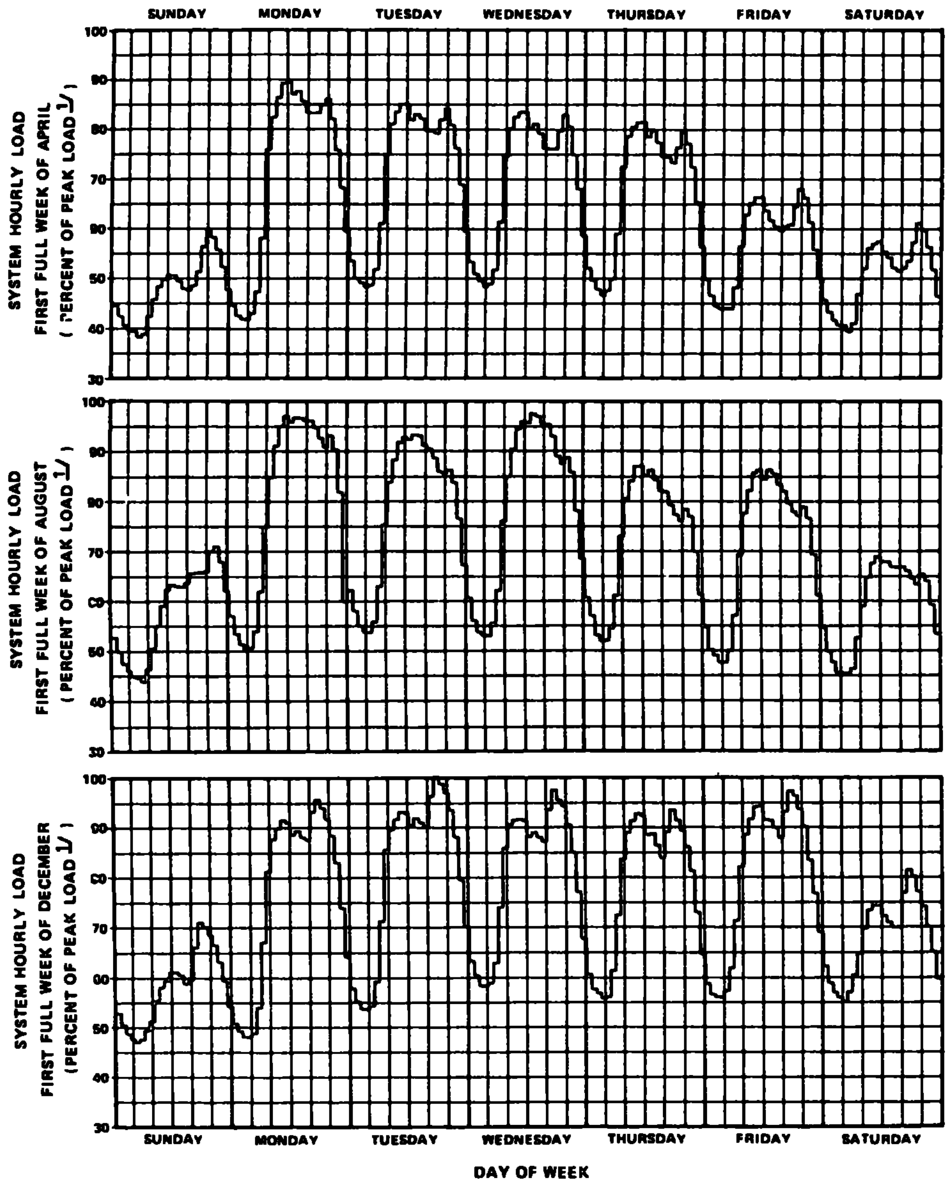
SUB-REGION CECO

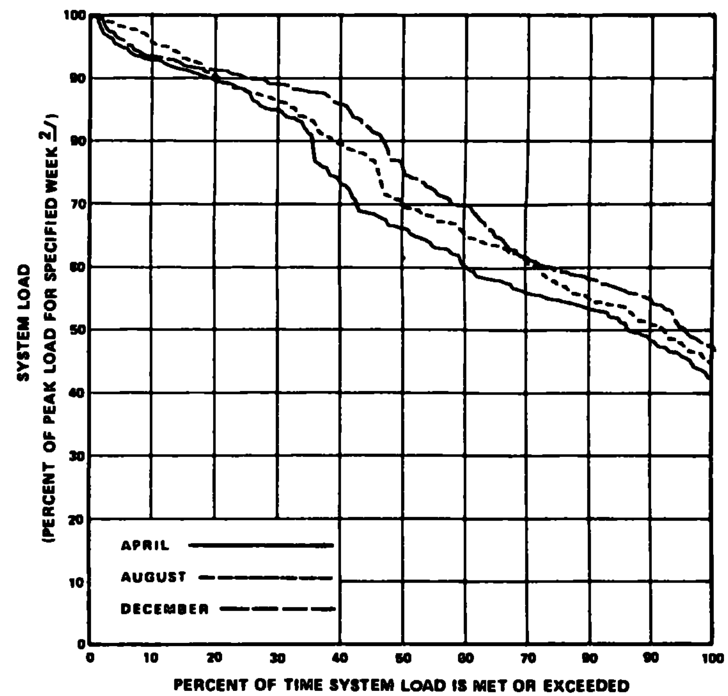
UTILITY. CECO

SHEET 1 OF 3

MARCH, 1979

EXHIBIT IV-6





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES.

SOURCE.

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

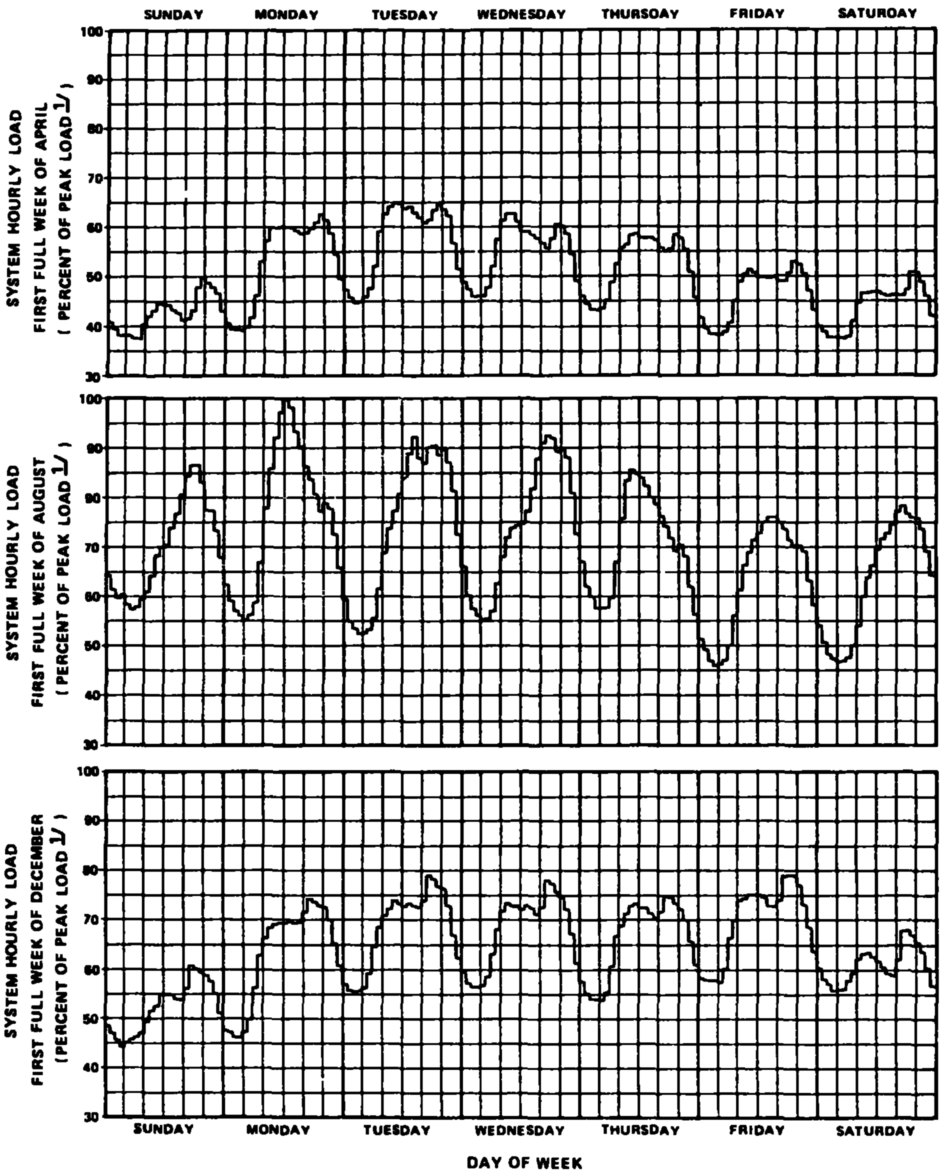
LOAD CURVES

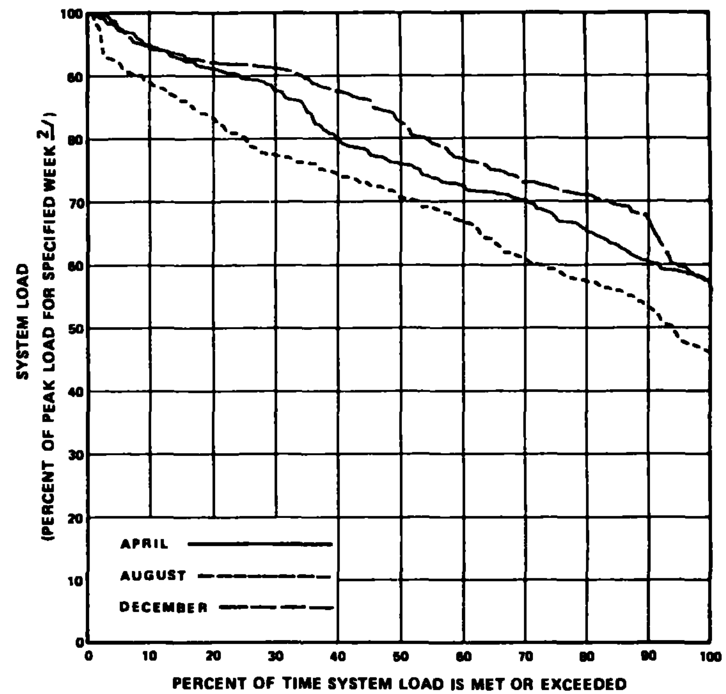
REGION: MAIN
SUB-REGION: WUMS
UTILITY. WUMS

SHEET 2 OF 3

DATE MARCH, 1979

EXHIBIT IV-6





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 16) FOR 1977

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

LOAD CURVES

REGION MAIN
SUB-REGION ILL-MO
UTILITY UNEC
SHEET 3 OF 3

DATE MARCH, 1979 — EXHIBIT IV-6

MAIN
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Commonwealth Edison Company	MW	5,058	-	8,356	1,616	-	-	-	-	1,250	-	22	607 1/	16,909
	%	29.9	-	49.4	9.6	-	-	-	-	7.4	-	0.1	3.6	100.0
Illinois Missouri Pool	MW	-	22	11,017	956	-	327	300	44	407	-	26	-	13,099
	%	-	0.2	84.1	7.3	-	2.5	2.3	0.3	3.1	-	0.2	-	100.0
Wisconsin-Upper Michigan System	MW	1,505	-	4,600	344	-	232	-	-	426	-	26	257 2/	7,391
	%	20.3	-	62.2	4.7	-	3.1	-	-	5.8	-	0.4	3.5	100.0
Central Illinois Light Company	MW	-	-	1,156	-	-	-	-	32	-	-	-	-	1,188
	%	-	-	97.3	-	-	-	-	2.7	-	-	-	-	100.0
Associated Electric Coop., Inc.	MW	-	-	1,767	-	-	-	-	-	44	-	16	-	1,827
	%	-	-	96.7	-	-	-	-	-	2.4	-	0.9	-	100.0
Southern Illinois Power Corp.	MW	-	-	110	-	-	-	-	-	-	-	-	-	110
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Springfield, Illinois, City Water, Light & Power Dept.	MW	-	-	294	37	-	-	-	-	46	-	-	-	377
	%	-	-	78.0	9.8	-	-	-	-	12.2	-	-	-	100.0
Western Illinois Power Coop., Inc.	MW	-	-	22	-	-	-	-	-	25	-	12	-	59
	%	-	-	37.3	-	-	-	-	-	42.4	-	20.3	-	100.0
Marquette, Michigan, Bd. of Light & Po.	MW	-	-	34	-	-	4	-	-	-	-	15	-	53
	%	-	-	64.2	-	-	7.5	-	-	-	-	28.3	-	100.0
Marshfield, Wisconsin Ele. & Water Dept.	MW	-	10	27	-	-	-	-	-	-	-	-	-	37
	%	-	27.0	73.0	-	-	-	-	-	-	-	-	-	100.0
Manitowoc, Wisconsin Public Utilities	MW	-	-	69	-	-	-	-	-	-	-	-	-	69
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Kaukauna, Wisconsin Ele. & Water Dept.	MW	-	-	34	-	-	9	-	20	-	-	6	-	69
	%	-	-	49.3	-	-	13.0	-	29.0	-	-	8.7	-	100.0
Columbia, Missouri, Water & Light Dept.	MW	-	36	52	-	-	-	-	10	-	-	-	-	98
	%	-	36.7	53.1	-	-	-	-	10.2	-	-	-	-	100.0
MAIN Total	MW	6,563	68	27,538	2,953	-	572	300	106	2,198	-	123	864	41,285
	%	15.9	0.2	66.6	7.2	-	1.4	0.7	0.3	5.3	-	0.3	2.1	100.0

1/ Jet Engine - Jet Fuel
2/ Jet Engine - FO2

Source: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

DEPARTMENT OF THE ARMY

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MAIN

EXISTING GENERATING CAPABILITY

DATE MARCH, 1978

EXHIBIT IV-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND MARCA REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MARCA**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT V-1

MARCA-REPORTING UTILITIES

Letter Code	
BEPC	Basin Electric Power Cooperative
CPA	Cooperative Power Association
DPC	Dairyland Power Cooperative
EILP	Eastern Iowa Light & Power Cooperative
ISP	Interstate Power Company
IELP	Iowa Electric Light & Power Company
CIPC	Central Iowa Power Cooperative
IIGE	Iowa-Illinois Gas & Electric Company
IPL	Iowa Power & Light Company
IPS	Iowa Public Service Company
CBPC	Corn Belt Power Cooperative
ISU	Iowa Southern Utilities Company
LSDP	Lake Superior District Power Company
LES	Lincoln Electric System
MPL	Minnesota Power and Light Company
MPC	Minnesota Power Cooperative, Inc.
MDU	Montana-Dakota Utilities Company
MPW	Muscatine Power & Water
NPPD	Nebraska Public Power District
NSP	Northern States Power Company
NWPS	Northwestern Public Service Company
OPPD	Omaha Public Power District
UPA	United Power Cooperative
WAPA	Western Area Power Administration
OTP	Otter Tail Power Company

SOURCE: "Report to the U.S. Department of Energy on Coordinated Bulk Power Supply Programs," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MARCA** **LIST OF UTILITIES**	
CONTRACT NO DACW72 – 78 – C – 0013 DATE MARCH, 1979	EXHIBIT V – 2

MARCA

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Average Annual Growth Rate-%: 1 yr	Average Annual Growth Rate-%: 5 yr	Peak Demand: Peak GW	Average Annual Growth Rate-%: 1 yr	Average Annual Growth Rate-%: 5 yr	Annual Load Factor-%
1970 1/	53.2	-	-	10.0	-	-	60.7
1971 1/	54.0	1.5	-	10.6	6.0	-	58.2
1972 2/	58.3	8.0	-	11.8	11.3	-	56.4
1973 3/	63.0	8.1	-	12.8	8.5	-	56.2
1974 3/	63.3	0.5	-	13.8	7.8	-	52.4
1975 3/	68.5	8.2	5.2	14.5	5.1	7.7	53.9
1976 4/	75.9	10.8	7.0	16.3	12.4	9.0	53.2
1977	85.7	12.9	8.0	17.5	7.4	8.2	55.9

Source: Correspondence, MAPP, 29 Nov 1978.

1/ Does not include Basin Electric Power Cooperative, Cooperative Power Association, and Western Area Power Administration/Upper Missouri Area.

2/ Does not include Basin Electric Power Cooperative, United Power Association, and Western Area Power Administration/Upper Missouri Area.

3/ Does not include Basin Electric Power Cooperative, and Western Area Power Administration/Upper Missouri Area.

4/ Does not include Western Area Power Administration/Upper Missouri Area.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **MARCA** **ELECTRIC POWER DEMAND**	
CONTRACT NO DACW72-78-C-0013 DATE MARCH, 1979	EXHIBIT V-3

MARCA

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES

(Percentage)

RESIDENTIAL

Representative Utilities	1970	1971	1972	1973	1974	1975	1976	1977
Interstate Power Company 1/	7.7	6.0	6.2	3.3	2.3	8.8	3.6	5.2
Iowa Electric Light and Power Company 1/	-	-	7.9 2/	4.1	2.9	7.5	0.2	-
Iowa Power and Light Company 7/10/	-	-	9.2 3/	6.6	1.5	11.3	(0.4)	6.5
Lake Superior District Power Company	4.8	5.4	6.3	1.4	4.1	2.6	3.9	0.9
Minnesota Power and Light Company	5.6	5.4	6.0	0.6	1.1	2.8	4.5	2.3
Northern States Power Company 4/8/11/	-	-	7.9 3/	1.7	0.0	6.9	3.2	0.1 5/
Omaha Public Power District 7/10/	10.3	4.7	6.9	9.0	1.4	11.1	(0.5)	3.1
Otter Tail Power Company 6/9/12/	-	-	7.0 3/	1.8	7.9	9.4	7.5	3.3

COMMERCIAL

Representative Utilities	1970	1971	1972	1973	1974	1975	1976	1977
Interstate Power Company 1/	9.6	10.5	6.9	5.5	(0.7)	7.3	4.9	4.2
Iowa Electric Light and Power Company 1/	-	-	8.3 2/	5.6	1.5	10.1	5.4	-
Iowa Power and Light Company 7/10/	-	-	7.6 3/	6.2	3.2	14.3	4.8	5.1
Lake Superior District Power Company	5.5	9.9	10.9	7.4	0.1	5.7	8.0	5.0
Minnesota Power and Light Company	10.2	8.0	7.0	5.8	0.5	6.7	11.5	2.6
Northern States Power Company 4/8/11/	-	-	8.4 3/	4.2	4.0	7.7	7.1	2.1 5/
Omaha Public Power District 7/10/	7.6	6.9	8.9	5.2	(7.5)	5.5	4.4	5.3
Otter Tail Power Company 6/9/12/	-	-	-	-	-	-	-	-

INDUSTRIAL

Representative Utilities	1970	1971	1972	1973	1974	1975	1976	1977
Interstate Power Company 1/	8.9	13.3	11.6	5.6	3.5	2.7	11.7	4.8
Iowa Electric Light and Power Company 1/	-	-	7.9 2/	9.9	3.1	5.2	10.0	-
Iowa Power and Light Company 7/10/	-	-	9.1 3/	5.5	0.3	2.1	5.2	9.8
Lake Superior District Power Company	(2.8)	(7.4)	15.0	30.0	(1.4)	(14.6)	8.0	31.9
Minnesota Power and Light Company	4.0	4.8	7.1	18.1	(0.3)	(3.6)	15.9	(2.1)
Northern States Power Company 4/8/11/	-	-	9.5 3/	6.7	0.0	2.5	4.9	3.9 5/
Omaha Public Power District 7/10/	7.0	(0.2)	1.6	9.4	30.7	2.0	9.2	2.5
Otter Tail Power Company 6/9/12/	-	-	13.6 3/	25.5	(1.9)	(1.9)	6.3	12.0

TOTAL

Representative Utilities	1970	1971	1972	1973	1974	1975	1976	1977
Interstate Power Company 1/	4.3	6.4	5.8	3.5	4.6	4.6	8.0	7.5
Iowa Electric Light and Power Company 1/	-	-	7.8 2/	6.8	3.3	8.4	4.9	-
Iowa Power and Light Company 7/10/	-	-	8.6 3/	6.2	1.6	8.1	2.6	6.9
Lake Superior District Power Company	3.3	2.3	9.5	11.8	2.4	(8.6)	2.4	13.2
Minnesota Power and Light Company	5.4	5.4	7.2	20.6	1.4	(0.1)	12.5	11.8
Northern States Power Company 4/8/11/	-	-	8.6 2/	8.6	(1.6)	9.1	8.8	18.6 5/
Omaha Public Power District 7/10/	(7.2)	3.4	5.2	7.7	1.0	(.5)	1.9	8.5
Otter Tail Power Company 6/9/12/	-	-	8.1 3/	11.1	0.8	11.4	19.2	1.7

Source: 1977 Annual Reports of the various utilities

1/ Includes Residential and Rural categories
2/ Six-year compound rate of growth
3/ Five-year compound rate of growth
4/ Calculated from data rounded to two significant figures
5/ Calculated from unrounded data
6/ Includes Residential and Farm categories
7/ Calculated from data listed as "Small General Service"
8/ Calculated from data listed at "Small Commercial and Industrial"
9/ Commercial and Industrial categories are grouped under "Industrial"
10/ Calculated from data listed at "Large General Service"
11/ Calculated from data listed as "Large Commercial and Industrial" and counted to two significant figures
12/ Includes Commercial and Industrial categories

MARCA

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

DATE: MARCH 1979 EXHIBIT V-4

MARCA
SYSTEM LOAD VARIATIONS[1/]
1977

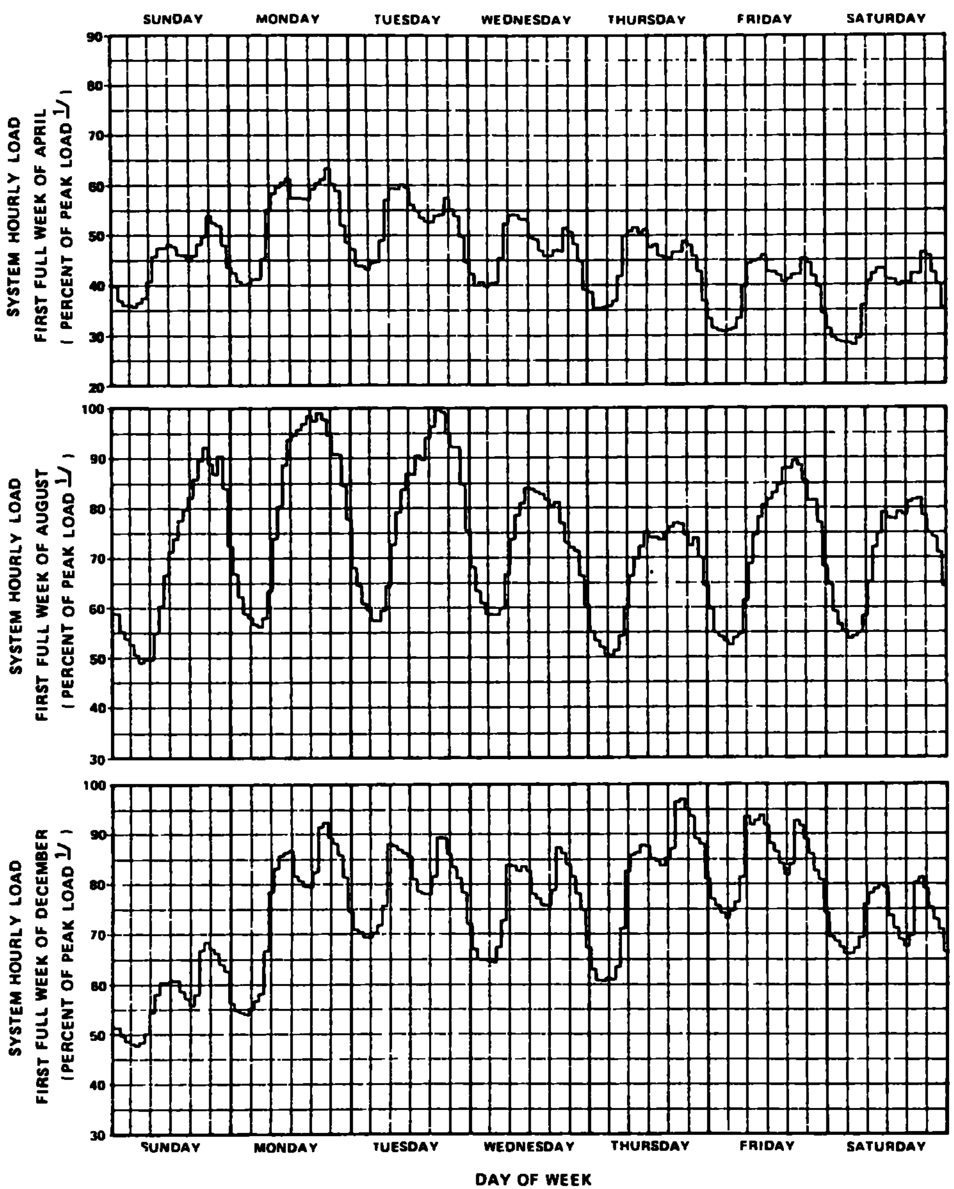
Representative Utilities	First Week of April: Peak Demand % of annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
Basin Electric Power Cooperative	NA[2/]	69.0	NA	80.1	NA	66.4	NA	NA	NA	NA
Dairyland Power Cooperative	78.8	67.0	69.3	68.9	10.0	73.1	576	Dec 6	2,508	49.7
Interstate Power Cooperative	69.5	78.8	86.7	72.6	85.9	81.9	668	July 5	3,533	60.4
Iowa Electric Light and Power Company	67.7	74.2	74.6	72.9	90.8	77.4	1,019	July 5	5,118	57.3
Iowa-Illinois Gas and Electric Company	61.9	71.8	86.9	64.9	69.2	77.2	872	July 14	3,926	51.4
Iowa Power and Light Company	54.1	76.4	71.1	71.5	69.2	78.0	1,064	July 6	4,392	47.1
Iowa Public Service Company	65.2	69.7	71.7	66.0	83.0	77.2	682	July 19	3,073	51.4
Minnesota Power and Light Company	91.4	84.8	51.4	79.2	73.4	83.4	973	June 27	5,626	66.0
Nebraska Public Power District	51.0	71.4	80.9	72.8	77.8	78.0	1,480	July 19	5,448	64.7
Northern States Power Company	68 2	70.9	77.3	68.5	80.2	77.5	4,278	July 19	20,186	53.9
MARCA							17,549[3/4/]		85,738[3/]	55.8

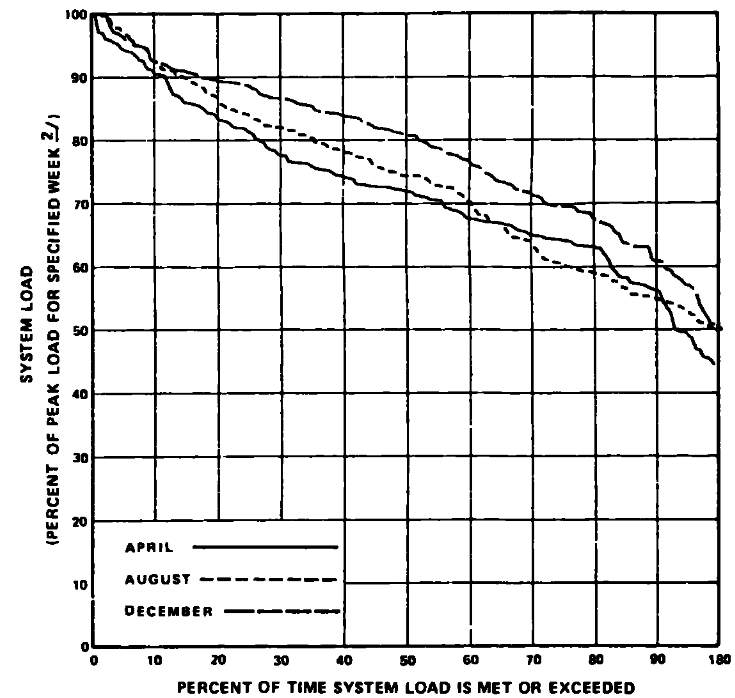
1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12
2/ NA = Not available.
3/ Source: MARCA, "Information Report on Corrdinated Regional Bulk Power Supply Programs," 1978.
4/ Non coincident peak.

MARCA
SYSTEM LOAD VARIATIONS, 1977

MARCH 1979

EXHIBIT V-5





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

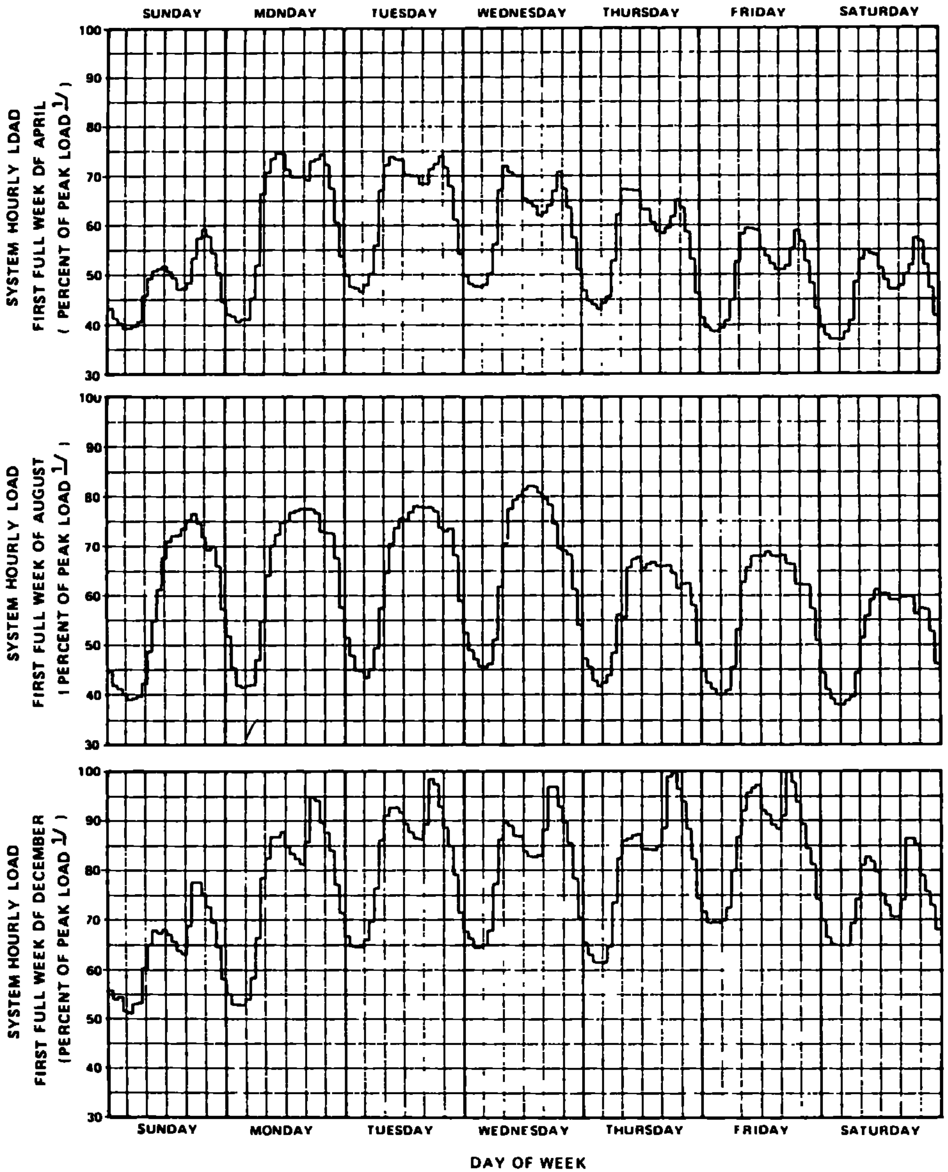
LOAD CURVES

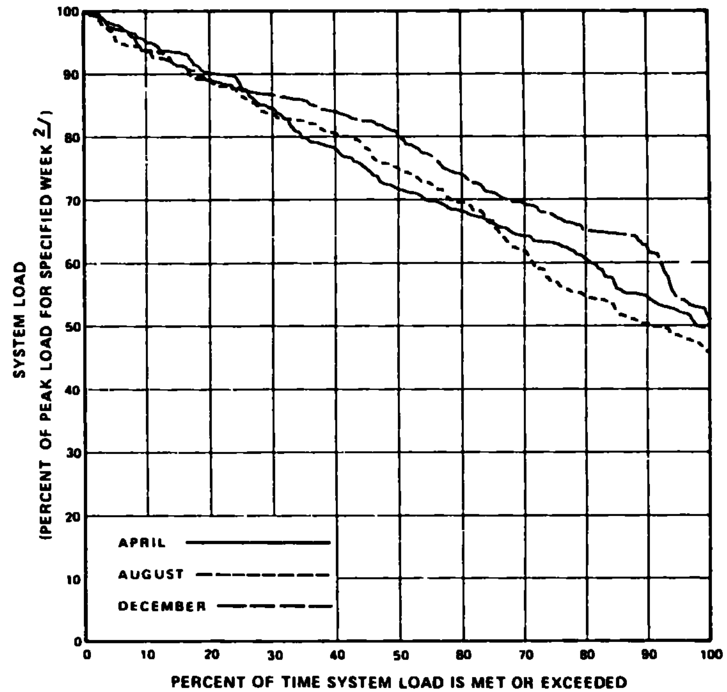
REGION MARCA
SUB-REGION MARCA
UTILITY NPPD

SHEET 1 OF 2

MARCH 1979

V-6





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL AUGUST AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL AUGUST OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

DEPARTMENT OF THE ARMY

LOAD CURVES

REGION MARCA
SUB-REGION MARCA
UTILITY IELP

SHEET 2 OF 2

MARCH 1979

EXHIBIT V-6

MARCA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Basin Electric Power Cooperative	MW	-	-	686	-	-	-	-	-	-	-	3	-	689
	%	-	-	99.6	-	-	-	-	-	-	-	0.4	-	100.0
Cooperative Power Association	MW	-	-	-	-	-	-	-	-	-	-	16	-	16
	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Diaryland Power Cooperative	MW	48	-	612	13	-	16	-	-	-	-	9	-	698
	%	6.9	-	67.7	1.9	-	2.3	-	-	-	-	2.0	-	100.0
Eastern Iowa Light and Power Coope-rative	MW	-	-	65	-	-	-	-	-	-	-	-	-	65
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Iowa Electric Light and Power Company Central Iowa Power Cooperative	MW	421	-	487	-	91	-	-	-	-	-	37	-	1,036
	%	40.6	-	47.0	-	8.8	-	-	-	-	-	3.6	-	100.0
Iowa Illinois Gas & Electric Co.	MW	396	-	371	74	115	2	-	-	146	-	1	-	1,105
	%	35.8	-	33.6	6.7	10.4	0.2	-	-	13.2	-	0.1	-	100.0
Iowa Power and Light Company	MW	-	30	442	30	-	-	-	-	350	-	-	-	852
	%	-	3.5	51.9	3.5	-	-	-	-	41.1	-	-	-	100.0
Iowa Public Service Company/Corn Belt Power Cooperative	MW	47	-	701	42	-	-	-	-	194	-	24	-	1,008
	%	4.7	-	69.5	4.2	-	-	-	-	19.2	-	2.4	-	100.0
Interstate Power Company	MW	-	-	722	43	-	-	-	-	54	-	11	-	830
	%	-	-	87.0	5.2	-	-	-	-	6.5	-	1.3	-	100.0
Iowa Southern Utilities Company	MW	-	-	412	-	-	-	-	-	-	-	9	-	421
	%	-	-	97.9	-	-	-	-	-	-	-	2.1	-	100.0
Lincoln Electric System	MW	-	-	-	22	-	-	-	-	107	-	-	-	129
	%	-	-	-	17.1	-	-	-	-	82.9	-	-	-	100.0
Lake Superior District Power Company	MW	-	-	92	-	-	13	-	20	-	-	4	-	129
	%	-	-	71.3	-	-	10.1	-	15.5	-	-	3.1	-	100.0

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

MARCA
EXISTING GENERATING CAPABILITY
SHEET 1 OF 2

CONTRACT NO. DACW72 [illegible]
DATE MARCH, 1979
EXHIBIT V-7

MARCA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Montana-Dakota Utilities Co.	MW	-	10	252	-	-	-	-	39	-	-	5	-	306
	%	-	3.3	82.4	-	-	-	-	12.7	-	-	1.6	-	100.0
Minnkota Power Coop., Inc.	MW	-	-	263	-	-	-	-	-	-	-	21	-	284
	%	-	-	92.6	-	-	-	-	-	-	-	7.4	-	100.0
Minnesota Power & Light Company	MW	-	-	1006	149	-	106	-	-	-	-	-	-	1261
	%	-	-	79.8	11.8	-	8.4	-	-	-	-	-	-	100.0
Muscatine Power and Water	MW	-	-	124	-	-	-	-	-	-	-	-	-	124
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Nebraska Public Power District	MW	778	158	325	8	-	127	-	-	187	-	36	-	1619
	%	48.1	9.8	20.1	0.5	-	7.8	-	-	11.5	-	2.2	-	100.0
Northern States Po. Company	MW	1603	-	3190	93	-	207	-	-	1501	-	44	-	6638
	%	24.1	-	48.1	1.4	-	3.1	-	-	22.6	-	0.7	-	100.0
Northwestern Public Service Company	MW	-	-	156	-	-	-	-	-	15	-	46	-	217
	%	-	-	71.9	-	-	-	-	-	6.9	-	21.2	-	100.0
Omaha Public Power District	MW	457	-	632	84	-	-	-	-	260	-	17	-	1450
	%	31.5	-	43.6	5.8	-	-	-	-	17.9	-	1.2	-	100.0
Otter Tail Power Co.	MW	-	-	372	-	-	4	-	-	29	-	22	-	427
	%	-	-	87.1	-	-	0.9	-	-	6.8	-	5.2	-	100.0
United Power Association	MW	-	-	216	-	-	-	-	-	-	-	21	-	237
	%	-	-	91.1	-	-	-	-	-	-	-	8.9	-	100.0
Western Area Power Adm./Upper Mi. Area	MW	-	-	-	-	-	2306	-	-	-	-	-	-	2306
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
MARCA Total	MW	3750	198	11126	558	206	2781	-	59	2843	-	326	-	21847
	%	17.2	0.9	50.9	2.6	0.9	12.7	-	0.3	13.0	-	1.5	-	100.0

Source: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

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MARCA
EXISTING GENERATING CAPABILITY
PAGE 2 OF 2

CONTRACT NO. DACW72 [illegible]
DATE MARCH, 1979
EXHIBIT V-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND NPCC REGIONAL REPORT

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH, 1979

EXHIBIT VI-1

NPCC - REPORTING UTILITIES

Letter Code	Sub-Region
	NEW ENGLAND
	Members of NPCC:
BOEC	Boston Edison Company
BULI	Burlington Electric Department
CEMP	Central Maine Power Company
CEVP	Central Vermont Public Service Corporation
EUAS	Eastern Utilities Associates System
GRMP	Green Mountain Power
NEES	New England Electric System
NEGE	New England Gas & Electric Association
NEUS	Northeast Utilities System
PSNH	Public Service Company of New Hampshire
UNIC	United Illuminating Company
	Other Reporting Utilities:
BRAI	Braintree Electric Light Department
BAHE	Bangor Hydro Electric Company
CAEL[1/]	Cambridge Electric Light Company
CACO[1/]	Canal Electric
CIUC	Citizen's Utilities
COLP[2/]	Connecticut Light & Power Company
COYA	Connecticut Yankee Atomic Power Company
FIGE	Fitchburg Gas & Electric Light Company
HAEL[2/]	Hartford Electric Light Company
HOGE	Holyoke Gas & Electric Department
HOWP[2/]	Holyoke Water Power Company
HLPD	Hudson Light & Power Department
IPSW	Ipswich Municipal Light Department
MAPS	Maine Public Service Company
MAYA	Maine Yankee Atomic Power Company
MMLD	Marblehead Municipal Light Department
MOEL[3/]	Montaup Electric Company
NEUS[2/]	Northeast Utilities Service Company
NEGB[1/]	New Bedford Gas & Edison Company
NEWP	Newport Electric Corporation
NSTD	Norwalk, Second Taxing District
NOWI	Norwich, Department of Public Utilities
PEAB	Peabody Municipal Light Department

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC

LIST OF UTILITIES

SHEET 1 OF 2

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH, 1979

EXHIBIT VI-2

NPCC - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
	NEW ENGLAND (Cont'd)
	Other Reporting Utilitites (Cont'd):
SELD	Shrewsbury Electric Light Department
TAUN	Taunton Municipal Light Department
VEYA	Vermont Yankee Nuclear Power Corporation
WMED	Wallingford Electric Department
WEME2/	Western Mass. Electric Company
YAEC	Yankee Atomic Electric Company
	NEW YORK
	Members of NPCC:
CEHG	Central Hudson Gas & Electric Corporation
COEN	Consolidated Edison Company of New York, Inc.
LOIL	Long Island Lighting Company
NEYE	New York State Electric & Gas Corporation
NIMP	Niagara Mohawk Power Corporation
ORRU	Orange and Rockland Utilities, Inc.
POAS	Power Authority of the State of New York
ROGE	Rochester Gas and Electric Corporation
	Non-Members of NPCC:
FREP	Village of Freeport
JAME	Jamestown Municipal Electric System
PLAT	City of Plattsburgh

1/ Subsidiary of New England Gas & Electric Association
2/ Subsidiary of Northeast Utilities
3/ Subsidiary of Eastern Utilities Associates

SOURCE: NPCC, "Data on Coordinated Regional Bulk Power Supply Programs," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

Note: This list of utilities has been assembled from the list reported in Item 2-A (found in Source above).

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **NPCC** **LIST OF UTILITIES** **SHEET 2 OF 2**	
CONTRACT NO DACW72-78-C-0013 DATE MARCH, 1979	EXHIBIT VI-2

NPCC

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

	Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate-% 1 yr	Annual Energy: Average Annual Growth Rate-% 5 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-% 1 yr	Peak Demand: Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
NPCC								
	1960	85.2	-	-	15.5	-	-	62.6 1/
	1965	114.7	-	6.1	20.4	-	5.6	64.2
	1970	153.1	-	5.9	27.1	-	5.8	64.5
	1971	165.5	8.1	-	29.1	7.4	-	64.9
	1972	175.7	6.2	-	31.3	7.6	-	63.9 1/
	1973	186.9	6.4	-	33.5	7.0	-	63.7
	1974	181.2	(3.0)	-	31.7	(5.4)	-	65.3
	1975	181.3	0.0	3.4	32.8	3.5	3.9	62.1
	1976	190.3	4.9	2.8	33.8	3.0	3.0	64.1 1/
	1977	194.2	9.0	2.0	35.4	4.7	2.5	62.6
NEW ENGLAND								
	1960	30.5	-	-	6.2	-	-	56.0 1/
	1965	41.8	-	6.5	8.6	-	6.8	55.5
	1970	58.3	-	6.9	11.8	-	6.5	56.4
	1971	65.2	11.9	-	12.1	2.5	-	61.5
	1972	70.6	8.3	-	13.5	11.6	-	59.5 1/
	1973	76.2	7.9	-	13.1	(2.9)	-	66.4
	1974	73.2	(3.9)	-	12.9	(1.5)	-	64.8
	1975	73.7	0.7	4.8	13.9	7.7	3.3	60.5
	1976	78.3	6.9	3.7	14.7	5.7	4.0	60.6 1/
	1977	79.8	1.9	2.5	15.1	2.7	2.3	60.3
NEW YORK								
	1960	54.7	-	-	10.1	-	-	61.7 1/
	1965	72.9	-	5.9	13.0	-	5.2	64.0
	1970	94.8	-	5.4	17.0	-	5.5	63.6
	1971	100.3	5.8	-	18.1	6.5	-	63.3
	1972	105.1	4.8	-	18.9	4.4	-	63.3 1/
	1973	110.7	5.3	-	20.4	7.9	-	61.9
	1974	108.0	(2.4)	-	19.6	(3.9)	-	62.9
	1975	107.6	(0.4)	2.6	20.0	2.0	3.3	61.4
	1976	112.0	4.1	2.2	19.3	(3.5)	1.3	66.1 1/
	1977	114.4	2.1	1.7	21.2	9.8	2.3	61.6

1/ Load factor was computed using 8784 hours to reflect leap year.

Source:
1. Federal Power Commission, "The 1970 National Power Survey" Part II, Washington D.C, 1970.
2. Report of member electric systems of the New York Power Pool, 1977, Volume 1.
3. Data from the New England Power Pool.
4. NPCC, "Data on coordinated regional bulk power supply programs" FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC
ELECTRIC POWER DEMAND

CONTRACT NO DACW72-78-C-0013
DATE MARCH, 1979

EXHIBIT VI-3

NPCC
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

RESIDENTIAL

	1971	1972	1973	1974	1975	1976	1977
New England Sub-Region							
- Maine	9.6	12.6	6.6	6.3	4.8	11.1	1.0
- New Hampshire	11.7	15.2	9.0	2.9	0.7	8.0	1.1
- Vermont	11.8	10.1	1.8	(0.8)	(1.1)	6.3	1.0
- Massachusetts	10.0	7.4	6.0	(2.5)	0.8	6.6	(1.0)
- Rhode Island	8.5	6.5	7.3	(3.1)	2.9	8.1	(2.4)
- Connecticut	6.8	7.0	4.6	(0.7)	0.1	5.3	1.8
New York Sub-Region							
- Central Hudson Gas & Electric Corporation	7.4	9.4	7.6	(1.4)	0.8	3.0	1.8
Consolidated Edison	-	1.5	7.6	(8.6)	2.6	0.5	4.0
- Long Island Lighting Company	7.4	4.7	8.5	(6.4)	2.9	2.8	2.4
- New York State Electric & Gas Corporation	7.2	8.1	5.2	2.4	6.0	6.0	4.0
- Niagara Mohawk Power Corporation	5.9	5.2	3.7	(0.3)	3.8	4.7	5.6
- Orange and Rockland Utilities Inc.	-	-	-	(4.4)	1.1	1.8	4.7
- Rochester Gas & Electric Corporation	6.3	6.2	3.2	(0.8)	5.1	5.7	3.3

COMMERCIAL

	1971	1972	1973	1974	1975	1976	1977
New England Sub-Region							
- Maine	12.0	11.5	7.7	0.2	5.4	12.3	5.3
- New Hampshire	12.0	10.7	9.1	(1.5)	4.0	6.3	6.0
- Vermont	15.6	(1.6)	2.6	(3.4)	3.9	7.9	4.2
- Massachusetts	9.3	11.3	9.8	(1.8)	7.9	6.6	0.4
- Rhode Island	12.0	7.4	8.3	(7.3)	1.3	8.7	1.8
- Connecticut	10.6	10.3	9.4	(4.1)	4.8	5.3	4.2
New York Sub-Region							
- Central Hudson Gas & Electric Corporation	7.7	10.1	9.3	(4.2)	6.2	3.0	3.5
Consolidated Edison	-	2.2	4.5	(6.8)	1.0	0.7	3.0
- Long Island Lighting Company	7.9	7.7	10.4	(4.3)	4.0	2.6*	3.7*
- New York State Electric & Gas Corporation	7.3	10.5	10.4	0.1	5.1	5.5	4.1
- Niagara Mohawk Power Corporation	8.4	8.9	8.7	(1.3)	5.4	1.6	6.0
- Orange and Rockland Utilities Inc.	-	-	-	(0.9)	4.8	2.9	1.1
- Rochester Gas & Electric Corporation	5.3	8.6	6.8	(2.7)	6.2	5.9	5.4

INDUSTRIAL

	1971	1972	1973	1974	1975	1976	1977
New England Sub-Region							
- Maine	0.8	6.4	3.7	5.3	(3.4)	5.4	10.2
- New Hampshire	11.1	9.2	9.2	(2.6)	(3.4)	10.4	3.6
- Vermont	3.9	22.7	7.3	(4.1)	(2.0)	8.8	5.5
- Massachusetts	1.3	6.3	6.7	(7.5)	(6.7)	3.3	4.8
- Rhode Island	3.6	7.1	6.9	(3.6)	(14.3)	10.1	0.8
- Connecticut	(2.3)	6.6	5.9	(3.8)	(8.6)	7.9	3.7
New York Sub-Region							
- Central Hudson Gas & Electric Corporation	4.3	3.6	3.5	(10.5)	(9.9)	(4.4)	6.3
Consolidated Edison	-	(2.5)	(2.8)	(16.0)	(11.3)	1.1	1.5
- Long Island Lighting Company	(0.3)	2.9	5.3	(8.1)	(3.6)	2.6*	3.7*
- New York State Electric & Gas Corporation	3.4	7.2	7.3	(4.7)	(0.8)	6.6	9.8
- Niagara Mohawk Power Corporation	(4.2)	1.3	5.6	(2.3)	(12.4)	6.6	3.7
- Orange and Rockland Utilities Inc.	-	-	-	(1.6)	2.1	6.5	5.4
- Rochester Gas & Electric Corporation	2.3	8.9	7.6	(5.5)	(4.5)	7.7	6.1

TOTAL

	1971	1972	1973	1974	1975	1976	1977
New England Sub-Region							
- Maine	6.3	9.8	5.7	4.5	1.8	9.2	6.1
- New Hampshire	11.8	12.0	9.1	0.0	(0.4)	8.6	2.9
- Vermont	10.3	10.6	3.7	(2.3)	(0.5)	7.4	3.0
- Massachusetts	7.0	7.9	7.8	(3.8)	1.0	5.7	1.0
- Rhode Island	7.9	7.0	7.5	(4.6)	(3.1)	8.9	(0.1)
- Connecticut	4.8	7.8	6.4	(2.7)	(1.2)	5.5	3.1
New York Sub-Region							
- Central Hudson Gas & Electric Corporation	6.3	7.2	6.5	(5.5)	(1.6)	0.6	3.7
Consolidated Edison	-	1.6	5.0	(8.2)	0.7	0.7	3.3
- Long Island Lighting Company	6.6	5.6	8.9	(5.8)	2.7	2.7	3.1
- New York State Electric & Gas Corporation	6.2	8.7	7.5	(0.3)	4.0	6.0	5.5
- Niagara Mohawk Power Corporation	1.5	4.4	5.9	(1.5)	3.0	4.5	4.9
- Orange and Rockland Utilities Inc.	-	-	-	(2.6)	2.5	3.6	2.1
- Rochester Gas & Electric Corporation	4.7	7.8	5.8	(3.0)	2.5	6.4	4.9

* Commercial and Industrial Growth Rates

Source the 1977 annual report for each utility in the council

NPCC
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

MARCH, 1979

EXHIBIT VI - 4

NPCC
SYSTEM LOAD VARIATIONS[1/]
1977

Representative Utilities	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
New England Sub-Region										
New England Power Exchange	80.5	75.3	87.5	73.7	92.2	76.1	14,622	Dec 12	79,734	61.4
Boston Edison Company	75.7	73.5	94.6	65.8	83.7	75.6	2,013	Jul, 21	10,088	57.2
Green Mountain Power Corporation	74.5	75.9	67.8	72.2	85.6	79.3	248	Dec 12	1,204	55.4
Public Service Company of New Hampshire	74.8	76.7	73.7	72.6	87.2	77.3	1,125	Dec 12	5,428	55.1
United Illuminating Company	79.8	69.4	92.2	71.9	85.7	75.4	944	July 21	4,899	59.2
Bangor Hydroelectric Company	85.8	78.1	87.7	79.2	100.0	76.4	204	Dec 6	1,235	71.1
Citizen's Utilities	62.7	72.3	60.1	68.4	71.2	72.6	39	Jan 18	214	63.2
City of Norwich	75.3	70.1	88.1	71.2	87.7	72.5	45	July 21	222	66.3
Connecticut Light & Power Company	79.8	73.5	87.6	73.1	93.6	73.7	1,965	Dec 12	10,433	60.6
Fitchburg Gas & Electric Light Company	75.4	70.1	94.2	69.7	91.3	74.9	72	Aug 30	378	60.2
Hartford Electric Light Company	72.6	72.4	90.4	80.6	86.4	74.5	1,157	July 21	5,822	57.4
Holyoke Gas & Electric Department	69.7	75.6	90.1	69.6	85.8	73.9	42	July 21	202	55.0
Holyoke Water Power Company	83.7	72.8	95.8	70.8	82.5	77.6	91	Dec 12	454	57.1
Hudson Light & Power Department	78.2	66.9	80.2	65.3	86.6	71.9	24	Dec 12	114	53.5
Maine Public Service Company	89.4	72.0	76.4	67.4	99.7	71.2	95	Dec 14	504	60.6
Peabody Municipal Light Department	66.1	70.1	87.3	62.5	76.4	71.6	60	Sep 2	267	50.3
Taunton Municipal Light Department	80.3	71.7	89.4	67.7	90.9	75.4	66	Dec 12	334	57.[illegible]
Western Mass. Electric Company	81.6	74.7	89.9	70.4	100.0	74.4	697	Dec 12	3,681	61.4

1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS
DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY
NPCC
SYSTEM LOAD VARIATIONS, 1977
SHEET 1 OF 2
MARCH, 1979
EXHIBIT VI-5

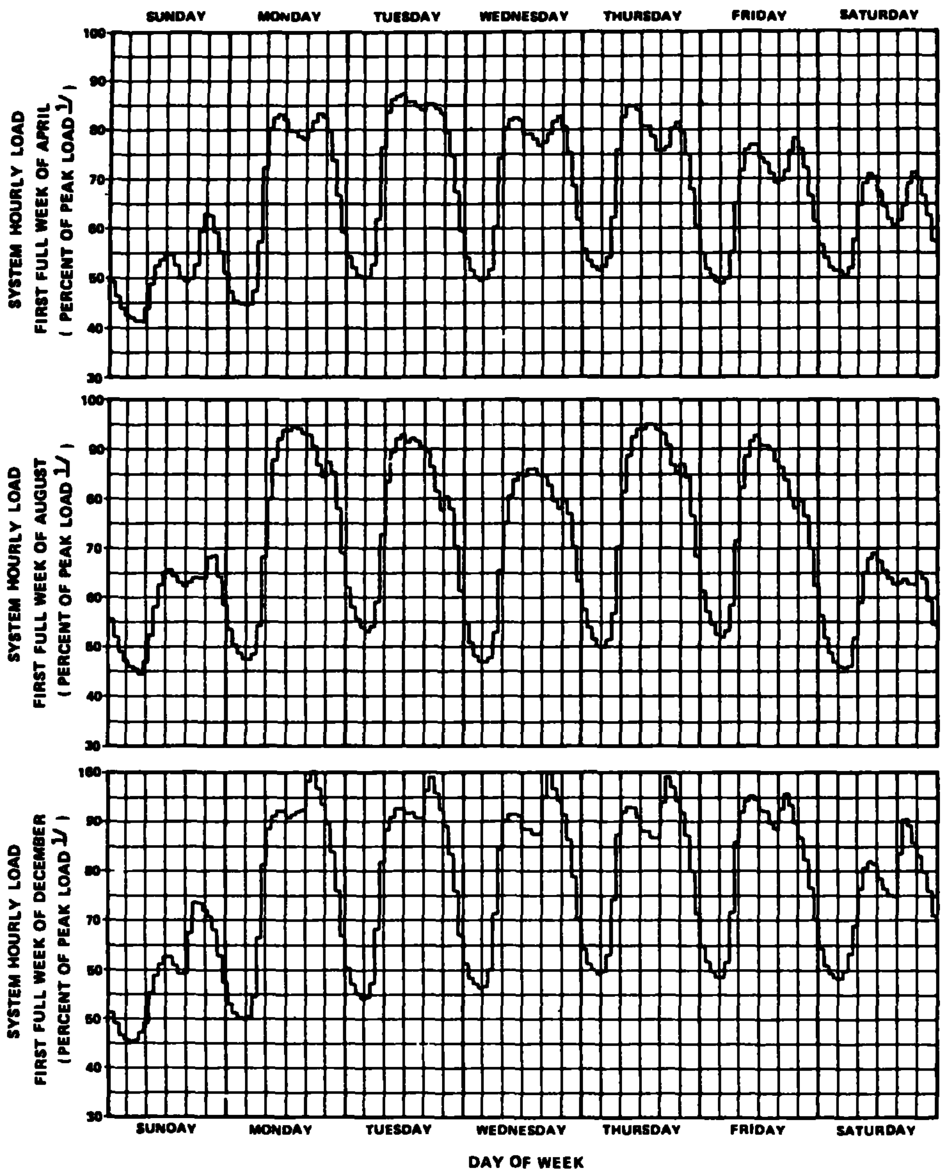
NPCC
SYSTEM LOAD VARIATIONS[1/]
1977

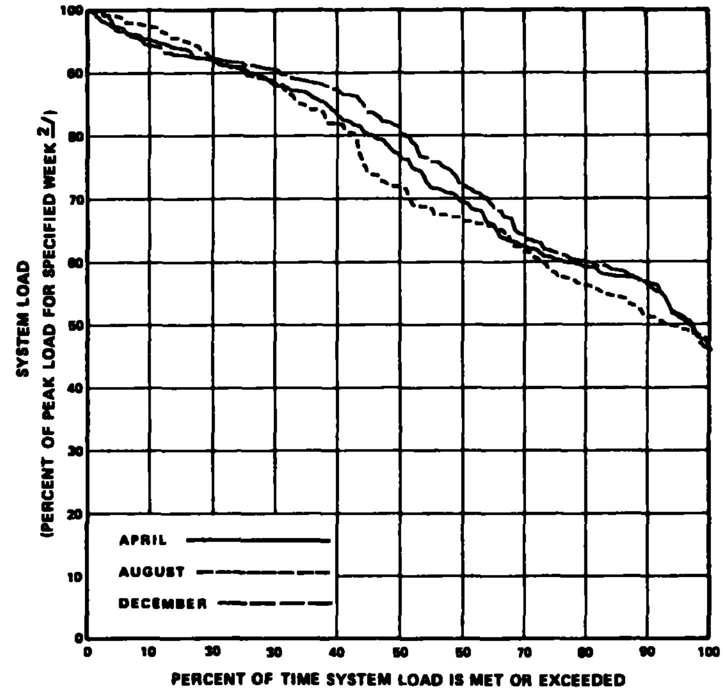
Representative Utilities	First Week of April		First Week of August		First Week of December		Annual			
	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand MW	Date	Net Energy GWh	Load Factor %
New York Sub-Region							21,214	-	114,400	61.6
Central Hudson Gas & Electric Corporation	75.0	72.8	92.4	74.7	93.8	77.3	631	July 21	3,423	61.9
Long Island Lighting Company	62.0	72.4	90.8	73.7	74.9	70.7	3,101	July 21	13,551	49.9
New York State Electric & Gas Corporation	80.3	77.7	90.8	76.9	93.5	78.5	2,062	Jan 18	11,309	62.6
Niagara Mohawk Power Corporation	83.3	80.2	84.5	78.1	95.5	79.3	5,284	Dec 12	31,321	67.7
Range and Rockland Utilities, Inc.	60.1	75.2	88.4	70.8	70.4	75.8	706	July 21	3,115	50.6
Power Authority of the State of New York	82.7	31.2	92.7	81.8	99.6	77.7	2,386	Dec 22	14,130	67.6
Rochester Gas & Electric Company	79.7	74.5	91.7	71.2	92.1	70.1	987	July 20	5,370	62.0
Village of Freeport	71.3	63.7	93.2	73.6	76.9	69.2	39	July 21	169	80.0
Jamestown Municipal Electric System	87.7	61.9	95.4	63.5	95.4	67.2	65	Aug 29	303	53.3

HARZA ENGINEERING COMPANY
DEPARTMENT OF THE ARMY

NPCC
SYSTEM LOAD VARIATIONS, 1977
SHEET 2 OF 2

DATE MARCH, 1979
EXHIBIT VI-5





NOTES.

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER.

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION: NPCC

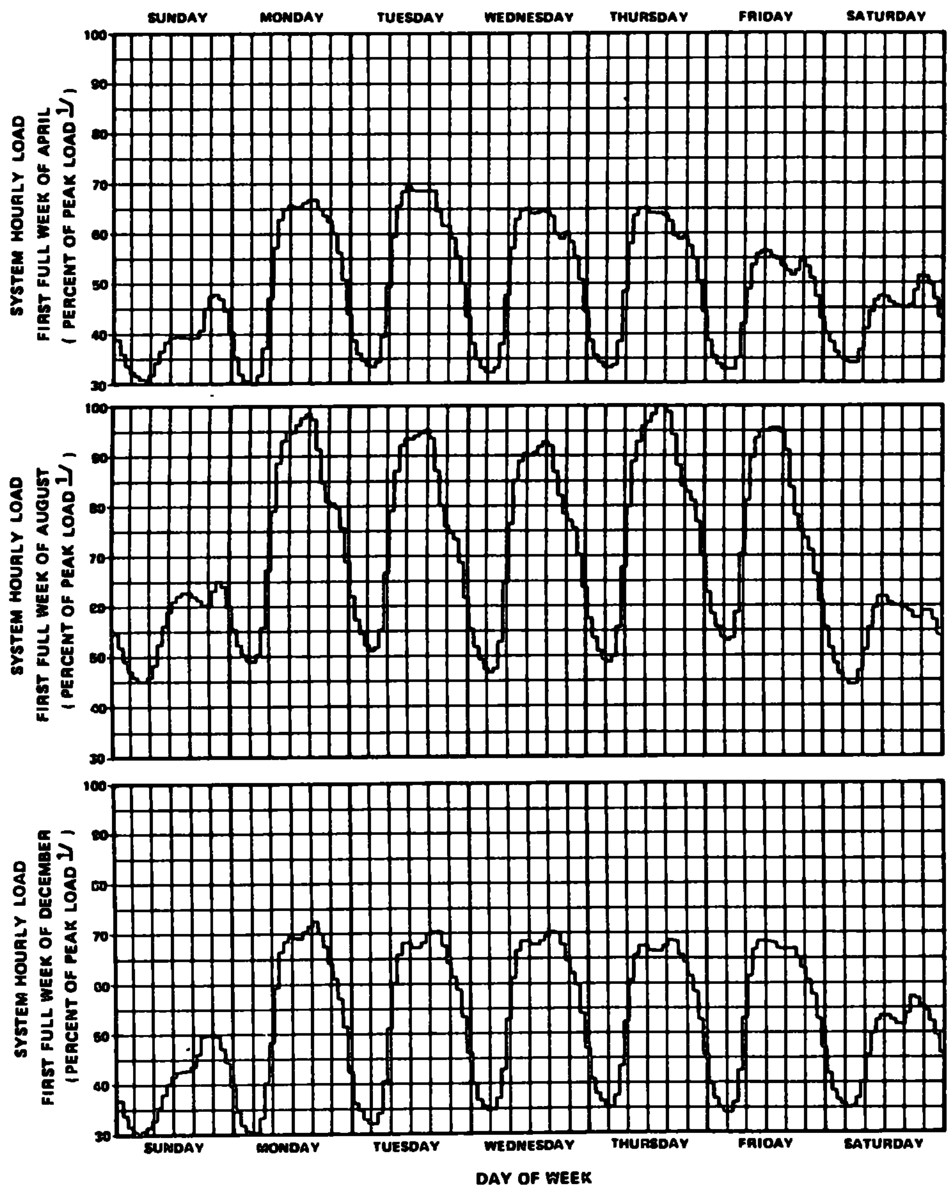
SUB-REGION: NEPOOL

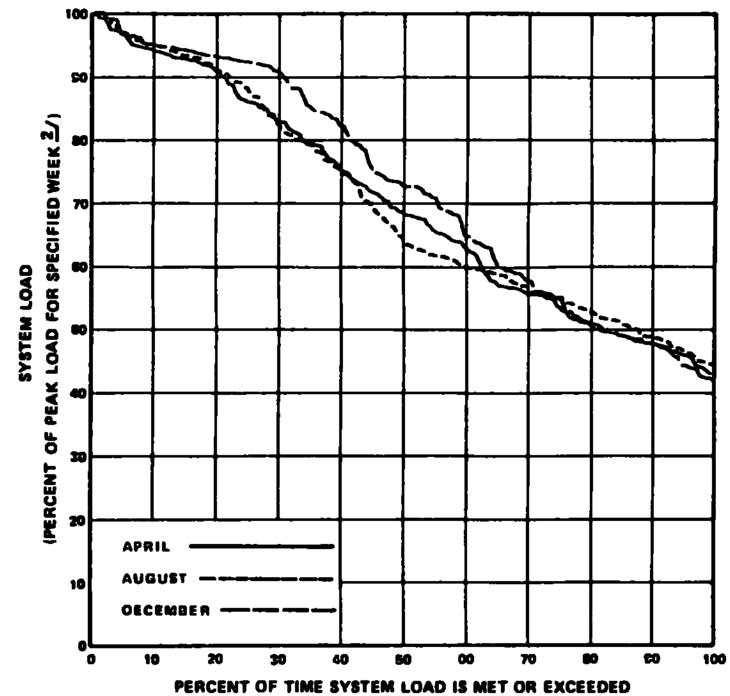
UTILITY NEPEX

SHEET 1 OF 3

MARCH, 1979

EXHIBIT VI-6





NOTES:

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES.

SOURCE:

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION: NPCC

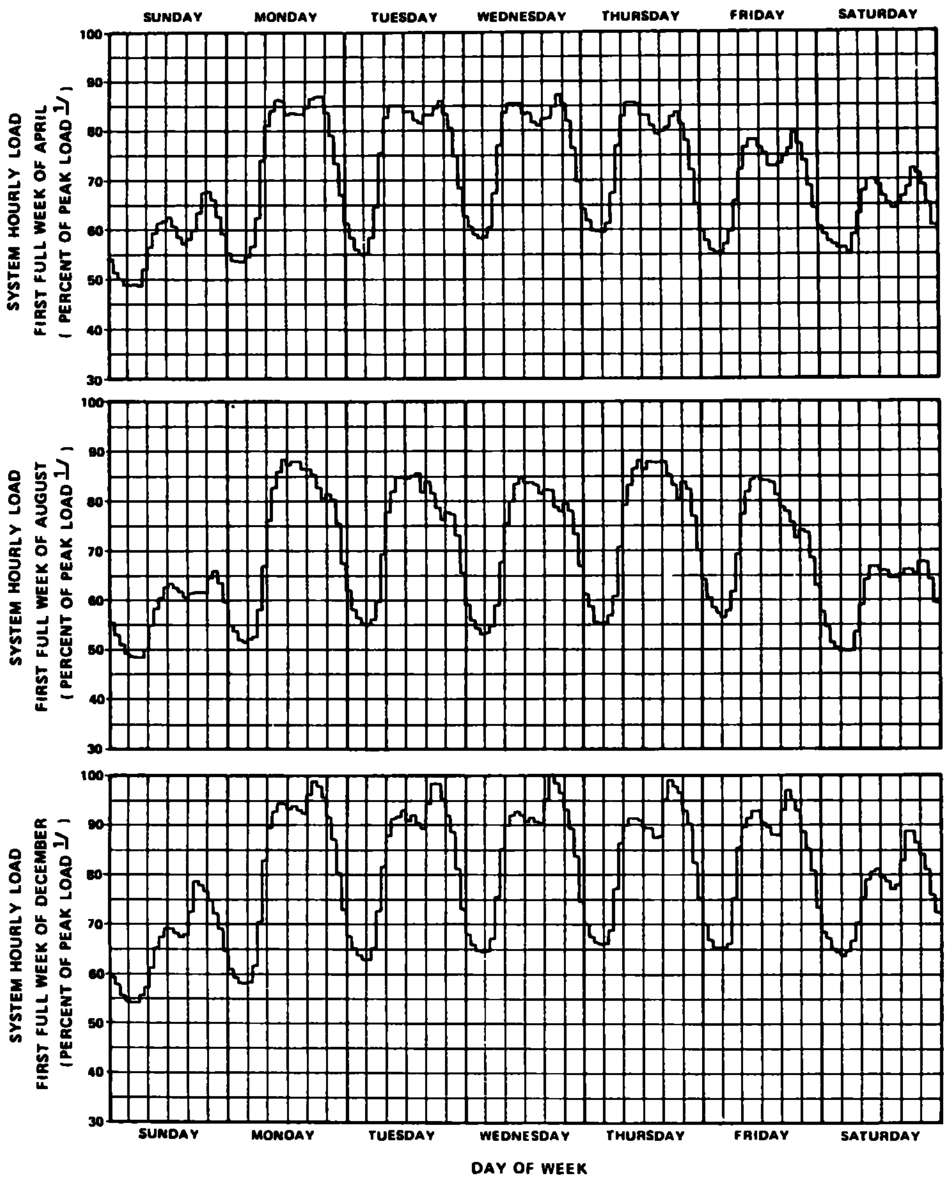
SUB-REGION: NYPP

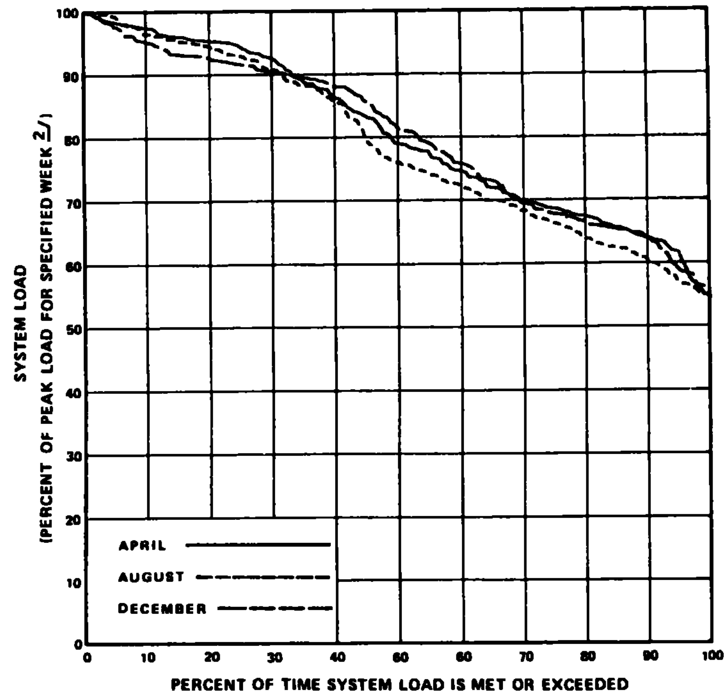
UTILITY COEN

SHEET 2 OF 3

DATE MARCH, 1979

EXHIBIT VI-6





NOTES

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION NPCC

SUB-REGION NYPP

UTILITY NIMP

SHEET 3 OF 3

MARCH, 1979

EXHIBIT VI-6

NPCC

NEW ENGLAND SUB-REGION

EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS

(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Boston Edison Company	MW	670	-	-	2058	-	-	-	-	305	-	-	-	3033
	%	22.1	-	-	67.9	-	-	-	-	10.0	-	-	-	100.0
Braintree Electric	MW	-	-	-	33	96	-	-	-	-	-	3	-	132
Light Department	%	-	-	-	25.0	72.7	-	-	-	-	-	2.3	-	100.0
Burlington Electric	MW	-	-	29	-	-	-	-	-	26	-	-	-	55
Department	%	-	-	52.7	-	-	-	-	-	47.3	-	-	-	100.0
Central Main Power Company	MW	-	-	-	410	-	302	-	-	46	-	5	-	763
	%	-	-	-	53.7	-	39.6	-	-	6.0	-	0.7	-	100.0
Central Vermont Public Service Corp.	MW	-	-	-	4	-	-	-	-	41	-	2	-	47
	%	-	-	-	8.5	-	-	-	-	87.2	-	4.3	-	100.0
Green Mountain Power	MW	-	-	-	-	-	71	-	-	72	-	9	-	152
	%	-	-	-	-	-	46.7	-	-	47.4	-	5.9	-	100.0
New England Electric	MW	-	-	-	2655	-	584	601	-	52	-	78	-	3970
System	%	-	-	-	66.9	-	14.7	15.1	-	1.3	-	2.0	-	100.0
Public Service Co.	MW	-	-	456	641	-	48	-	-	111	-	3	-	1259
of New Hampshire	%	-	-	36.2	50.9	-	3.8	-	-	8.8	-	0.3	-	100.0
United Illuminating	MW	-	-	-	1389	-	-	-	-	21	-	-	-	1410
Company	%	-	-	-	98.5	-	-	-	-	1.5	-	-	-	100.0

Source: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4 Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
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CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC

EXISTING GENERATING CAPABILITY

CONTRACT NO. DACW72-78-C-[illegible]

DATE MARCH, 1979

EXHIBIT VI-7

NPCC
NEW ENGLAND SUB-REGION
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Bangor Hydro Electric	MW	-	-	-	60	-	29	-	-	4	-	24	-	117
Company	%	-	-	-	51.3	-	24.8	-	-	3.4	-	20.5	-	100.0
Cambridge Electric	MW	-	-	-	92	-	-	-	-	48	-	-	-	140
Light Company	%	-	-	-	65.7	-	-	-	-	34.3	-	-	-	100.0
Canal Electric	MW	-	-	-	864	-	-	-	-	-	-	-	-	864
	%	-	-	-	100.0	-	-	-	-	-	-	-	-	100.0
Citizen's Utilities	MW	-	-	-	-	-	-	-	-	-	-	10	-	10
	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Connecticut Light &	MW	772	-	-	1,362	-	98	561	-	209	-	6	-	3,008
Power Company	%	25.7	-	-	45.3	-	3.3	18.6	-	6.9	-	0.2	-	100.0
Connecticut Yankee	MW	575	-	-	-	-	-	-	-	-	-	-	-	575
Atomic Power Co.	%	100.0	-	-	-	-	-	-	-	-	-	-	-	100.0
Fitchburg Gas &	MW	-	-	-	21	-	-	-	-	29	-	-	-	50
Electric Light Co.	%	-	-	-	42.0	-	-	-	-	58.0	-	-	-	100.0
Hartford Electric	MW	408	-	-	833	-	10	280	-	275	-	-	-	1,806
Light Company	%	22.6	-	-	46.1	-	0.6	15.5	-	15.2	-	-	-	100.0
Holyoke Gas &	MW	-	-	-	25	-	2	-	-	10	-	-	-	37
Electric Department	%	-	-	-	67.6	-	5.4	-	-	27.0	-	-	-	100.0
Holyoke Water Power	MW	-	-	-	152	-	29	-	-	-	-	-	-	181
Company	%	-	-	-	84.0	-	16.0	-	-	-	-	-	-	100.0
Hudson Light & Power	MW	-	-	-	-	-	-	-	-	-	-	20	-	20
Department	%	-	-	-	-	-	-	-	-	-	-	100.0		100.0
Ipswich Municipal	MW	-	-	-	-	-	-	-	-	-	-	9	-	9
Light Department	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Maine Public Service	MW	-	-	-	23	-	2	-	-	-	-	12	-	37
Company	%	-	-	-	62.2	-	5.4	-	-	-	-	32.4	-	100.0
Maine Yankee Atomic	MW	781	-	-	-	-	-	-	-	-	-	-	-	781
Power Company	%	100.0	-	-	-	-	-	-	-	-	-	-	-	100.0

HARZA ENGINEERING COMPANY | DEPARTMENT OF THE ARMY

NPCC

EXISTING GENERATING CAPABILITY

PAGE 2 OF 5

DATE: MARCH, 1979

EXHIBIT VI-7

NPCC
NEW ENGLAND SUB-REGION
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Marblehead Municipal	MW	-	-	-	-	-	-	-	-	-	-	6	-	6
Light Department	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Montaup Electric Co.	MW	-	-	-	624	-	-	-	-	48	-	-	-	672
	%	-	-	-	92.9	-	-	-	-	7.1	-	-	-	100.0
New Bedford Gas &	MW	-	-	-	79	-	-	-	-	-	-	14	-	93
Edison Company	%	-	-	-	84.9	-	-	-	-	-	-	15.1	-	100.0
Newport Electric	MW	-	-	-	14	-	-	-	-	-	-	14	-	28
Corp.	%	-	-	-	50.0	-	-	-	-	-	-	50.0	-	100.0
Norwalk, Second	MW	-	-	-	-	-	-	-	-	-	-	15	-	15
Taxing District	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Norwich, City of	MW	-	-	-	18	-	3	-	-	-	-	-	-	21
	%	-	-	-	85.7	-	14.3	-	-	-	-	-	-	100.0
Peabody Municipal	MW	-	-	-	-	-	-	-	-	21	-	10	-	31
Light Department	%	-	-	-	-	-	-	-	-	67.7	-	32.3	-	100.0
Shrewsbury Electric	MW	-	-	-	-	-	-	-	-	-	-	11	-	11
Light Department	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Taunton Municipal	MW	-	-	-	84	215	-	-	-	-	-	-	-	299
Light Department	%	-	-	-	28.1	71.9	-	-	-	-	-	-	-	100.0
Vermont Yankee	MW	524	-	-	-	-	-	-	-	-	-	-	-	524
Nuclear Power Corp.	%	100.0	-	-	-	-	-	-	-	-	-	-	-	100.0
Wallingford Electric	MW	-	-	20	-	-	-	-	-	-	-	-	-	20
Department	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
Western Mass.	MW	277	-	-	211	-	105	190	-	153	-	-	-	936
Electric Company	%	29.6	-	-	22.5	-	11.2	20.3	-	16.3	-	-	-	100.0
Yankee Atomic	MW	176	-	-	-	-	-	-	-	-	-	-	-	176
Electric Company	%	100.0	-	-	-	-	-	-	-	-	-	-	-	100.0
New England Sub-Region	MW	4,183	-	505	11,642	311	1,283	1,632	-	251	-	251	-	21,288
	%	19.6	-	2.4	54.7	1.5	6.0	7.7	-	1.2	-	1.2	-	100.0

Source: Based on winter generating capability reported to the Department of Energy, FEPC (FPC) Order 383-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
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DEPARTMENT OF THE ARMY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC

EXISTING GENERATING CAPABILITY

SHEET 3 OF 5

CONTRACT NO [illegible]
DATE MARCH, 1979
EXHIBIT VI-7

NPCC
NEW YORK SUB-REGION
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Central Hudson Gas & Elec. Corp.	MW	-	-	-	731	-	46	-	-	48	-	5	-	830
	%	-	-	-	88.1	-	5.5	-	-	5.8	-	0.6	-	100.0
Consolidated Edison Co. of New York	MW	864	-	-	6,850	-	-	-	-	2,639	-	-	-	10,353
	%	8.3	-	-	66.2	-	-	-	-	25.5	-	-	-	100.0
Long Island Lighting Company	MW	-	-	-	2,563	-	-	-	-	1,433	-	12	-	4,008
	%	-	-	-	63.9	-	-	-	-	35.8	-	0.3	-	100.0
New York State Elec. & Gas Corporation	MW	-	-	1,537	-	-	40	-	-	-	-	13	-	1,590
	%	-	-	96.7	-	-	2.5	-	-	-	-	0.8	-	100.0
Niagara Mohawk Power Corporation	MW	610	-	1,471	2,105	-	661	-	-	346	-	8	-	5,201
	%	11.7	-	28.3	40.5	-	12.7	-	-	6.7	-	0.1	-	100.0
Orange and Rockland Utilities, Inc.	MW	-	-	-	902	-	44	-	-	86	-	-	-	1,032
	%	-	-	-	87.4	-	4.3	-	-	8.3	-	-	-	100.0
Power Authority of the State of New York	MW	1,673	-	-	775	-	3,200	1,000	-	-	-	-	-	6,648
	%	25.2	-	-	11.7	-	48.1	15.0	-	-	-	-	-	100.0
Rochester Gas & Electric Corp.	MW	400	3	340	96	-	50	-	-	36	-	-	-	925
	%	43.2	0.3	36.8	10.4	-	5.4	-	-	3.9	-	-	-	100.0
City of Plattsburg	MW	-	-	-	-	-	-	-	-	-	-	3	-	3
	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Village of Freeport	MW	-	-	-	-	-	-	-	-	21	-	32	-	53
	%	-	-	-	-	-	-	-	-	39.6	-	60.4	-	100.0
Jamestown Municpal Electric System	MW	-	-	78	-	-	-	-	-	-	-	-	-	78
	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
NEW YORK Sub-Region	MW	3,547	3	3,426	14,022	-	4,041	1,000	-	4,609	-	73	-	30,721
	%	11.5	0.0	11.2	45.6	-	13.2	3.3	-	15.0	-	0.2	-	100.0

SOURCE: Based on winter generating capability reported to the Department of Energy, (FPC) Order 383-4, Docket R-362, April 1978.

NPCC
EXISTING GENERATING CAPABILITY
SHEET 4 OF 5
DATE MARCH, 1979
EXHIBIT VI-7

NPCC - SUMMARY
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
New England Sub-Region	MW	4,183	-	505	11,652	311	1,283	1,632	-	1,471	-	251	-	21,288
	%	19.6	-	2.4	54.7	1.5	6.0	7.7	-	6.9	-	1.2	-	100.0
New York Sub-Region	MW	3,547	3	3,426	14,022	-	4,041	1,000	-	4,609	-	73	-	30,721
	%	11.5	0.0	11.2	45.6	-	13.2	3.3	-	15.0	-	0.2	-	100.0
NPCC Total	MW	7,730	3	3,931	25,674	311	5,324	2,632	-	6,080	-	324	-	52,009
	%	14.9	0.0	7.6	49.4	0.6	10.1	5.1	-	11.7	-	0.6	-	100.0

Source: Based on winter generating capability reported to the Department of Energy FERC (FPC) Order 384-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

NPCC

EXISTING GENERATING CAPABILITY

SHEET 6 OF 6

CONTRACT NO [illegible]

DATE MARCH, 1979

EXHIBIT VI-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND SERC REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **SERC**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT VII-1

SERC - REPORTING UTILITIES

Letter Code	Sub-Region
	FLORIDA
	Members of SERC:
FLPL	Florida Power & Light Company
FLPC	Florida Power Corporation
FOPC	Fort Pierce Utilities Authority
GAMW	Gainesville/Alachua County Regional Utilities Board
JACO	Jacksonville Electric Authority
LALW	City of Lakeland
ORLA	Orlando Utilities Commission
TALL	City of Tallahassee
TAEC	Tampa Electric Company
VEBM	City of Vero Beach
	Non-Members of SERC:
HSTX	City of Homestead
LWUA	Lake Worth Utilities Authority
SECI	Seminole Electric Cooperative
	SOUTHERN COMPANIES
	Members of SERC:
ALEC	Alabama Electric Cooperative, Inc.
ALAP	Alabama Power Company 1/
CCPC	Crisp County Power Commission
GEPC	Georgia Power Company 1/
GUPC	Gulf Power Company
MIPR	Mississippi Power Company
SAEP	Savannah Electric & Power Company
SEPA	Southeastern Power Administration
SOMI	South Mississippi Electric Power Association
SOEG	Southern Electric Generating Company 2/

1/ 50% owned by Alabama Power Company and 50% owned by Georgia Power Company

2/ The Southern Company plus Southern Services, Inc.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SERC

LIST OF UTILITIES

SHEET 1 OF 2

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH, 1979

EXHIBIT VII-2

SERC -REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
	TENNESSEE VALLEY
	Members of SERC:
NAPL	Nantahala Power & Light Company
TAPI	Tapoco, Inc.
TVA	Tennessee Valley Authority
	VIRGINIA-CAROLINAS
	Members of SERC:
CAPO	Carolina Power & Light Company
DUPC	Duke Power Company
SOCG	South Carolina Electric & Gas Company
SOCA	South Carolina Public Service Authority
SEPA	Southeastern Power Administration
VIEP	Virginia Electric & Power Company
YADI	Yadkin, Inc.

Source: SERC "Coordinated Bulk Power Supply Program", FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

SERC

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate-% 1 yr	Annual Energy: Average Annual Growth Rate-% 5 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-% 1 yr	Peak Demand: Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
1960	147.5	-	-	25.9	-	-	64.8 1/
1965	203.1	-	6.6	33.8	-	5.5	68.6
1970	299.1	-	8.0	52.9	-	9.4	64.5
1973	382.8	-	-	67.6	-	-	64.6
1974	381.0	(0.4)	-	69.5	2.8	-	62.6
1975	389.8	2.3	5.4	71.8	3.3	6.3	62.0
1976	414.0	6.2	-	74.2	3.3	-	63.5 1/
1977	442.2	6.8	-	79.9	7.7	-	63.2

1/ Load factor was computed using 8784 hours to reflect leap year.

Source:
1. Federal Power Commission, "The 1970 National Power Survey" Part II, Washington D.C., 1970.
2. Department of Energy, Energy Information Report on annual report of monthly comparisons of peak demands and energy for loads - 1973 to 1977", Washington D.C., May 1978.
3. "SERC Report on coordinated bulk power supply program", FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **SERC** **ELECTRIC POWER DEMAND**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT VII-3

SERC

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES

(Percentage)

Representative Utilities	RESIDENTIAL							COMMERCIAL							INDUSTRIAL							TOTAL						
	1971	1972	1973	1974	1975	1976	1977	1971	1972	1973	1974	1975	1976	1977	1971	1972	1973	1974	1975	1976	1977	1971	1972	1973	1974	1975	1976	1977
Florida Sub-Region																												
- Florida Power & Light Company	-	-	14.8	(0 1)	3.0	1.8	8.2	-	-	21.3	8.5	7.3	2.2	6.3	-	-	11.6	(4.8)	(4.2)	2.4	6.2	-	-	15.9	3.1	3.9	2.0	7 3
- Florida Power Corporation	-	-	-	(8.8)	2.4	6.3	18.8	-	-	-	3.5	8 6	3.5	6.9	-	-	-	3 1	2.4	8.5	4.6	-	-	-	(3.1)	4.1	6.8	8 3
- Tampa Electric Company	9.0	9.8	17.7	(8.6)	2.8	0.2	7.8	12.0	14.6	14.2	7.5	7.8	2.1	5.6	(2.0)	2.5	7 9	3.3	6.3	8.1	12.5	9.4	7.4	12 8	2.7	5.3	3 9	9.1
-																												
Southern Company Sub-Region																												
- Alabama Power Company	6.2	9.0	18.3	(0.3)	5.8	5.1	8.2	5.8	11.9	10 4	2.7	7 1	3.9	6.8	(1.7)	10.8	5.7	1.1	(2.3)	18.5	8.2	4.5	7.8	8 1	1.0	2.1	7.4	7.9
- Georgia Power Company	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.9	6.5	6.0	4.0	5.3
- Gulf Power Company	14.8	9.1	12.4	1.9	2.9	8 4	5.4	10.7	14.4	10.0	2.4	7 4	8.4	7.0	9.0	12.4	5.6	(4.1)	1.1	7.2	4.1	9.4	12 9	9.5	0 8	3 4	8 8	5.4
- Mississippi Power Company	7.6	13.1	5 9	(4 7)	3.5	1.1	8.2	11.5	14.8	7.0	(2 6)	4.3	4.7	4.5	8.4	0.8	6.1	2 7	4.8	8.6	3.9	8.8	7.4	6.2	(0.1)	4.3	5.6	5.2
Tennessee Valley Sub-Region																												
Tennessee Valley Authority	1 7	0.1	11.5	0.0	3.9	8.1	17.7	4.7	8.8	8.6	2.2	(3.5)	5.8	12.9	(3.3)	(7.9)	11.6	8.8	(8.3(	(8.6)	14.0	1.1	0 1	18.5	3.1	(2.2)	0.0	15.1
Virginia Carolinas Sub-Region																												
- Carolina Power & Light Company																												
- Duke Power Company	-	-	-	1.4	4.7	4.8	18.0	-	-	-	(3.2)	7.3	5.6	8.0	-	-	-	(5.1)	(6.4)	18.0	4.2	-	-	-	(2.9)	8.0	7.5	6.7
- South Carolina Public Service Authority																												
- South Carolina Electric & Gas Company	-	-	13.7	(1.1)	4.6	5.7	9.7	-	-	13 9	1 1	6 7	6.7	7 1	-	-	-	-	-	-	-	-	-	10.1	8.1	1.3	8.7	8.4
- Virginia Electric & Power Company	3.2	8 1	12.9	(0.6)	5.3	7.4	6 6	6 5	8.2	13.3	(0 3)	9.1	6.1	3.6	5.1	9.7	7.8	2.2	(4.5)	11.2	0.2	4.7	8.5	11.7	0.0	4.0	7.8	4.1

Source: the 1977 annual report for each utility in the council

SERC

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

MARCH, 1979

EXHIBIT VII – 4

SERC
SYSTEM LOAD VARIATIONS1/
1977

Representative Utilities or Power Groups	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
Florida Sub-region										
Florida Power & Light Company	71.6	66.9	81.3	74.2	69.3	69.7	8,606	Jan 19	40,712	54.0
Florida Power Corporation	63.2	70.5	73.0	72.9	81.9	61.6	3,899	Jan 19	17,150	50.2
Fort Pierce Utilities Authority	63.3	66.0	74.7	71.3	68.4	64.2	79	Jan 19	321	46.4
Gainesville Alachua County Reg. Ut. B.	70.2	60.7	85.9	69.9	79.4	65.1	161	July 13	736	52.2
Jacksonville Electric Authority	69.9	68.1	94.5	73.2	73.0	68.0	1,243	July 7	5,952	54.7
City of Lakeland	57.6	60.9	75.5	63.6	73.5	58.2	271	Jan 19	1,048	44.2
Orlando Utilities Commission	70.1	61.6	78.2	69.0	75.4	62.5	468	Jan 19	2,054	50.1
City of Tallahassee	62.4	68.2	97.0	65.3	84.4	65.7	234	July 13	1,076	52.5
Tampa Electric Company	76.9	75.0	82.8	79.0	87.2	72.2	1,784	Jan 18	10,131	64.8
City of Vero Beach	40.2	64.0	49.1	70.8	41.1	64.1	112	Jan 20	288	29.0
Tennessee Valley Sub-region										
Tennessee Valley Authority	77.3	80.7	84.5	82.5	95.1	78.5	21,803	Jan 10	124,618	78.4

1/ Computation based on data from schedules 14 and 15 1977 FERC - Form 12.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SERC

SYSTEM LOAD VARIATIONS, 1977

SHEET 1 OF 2

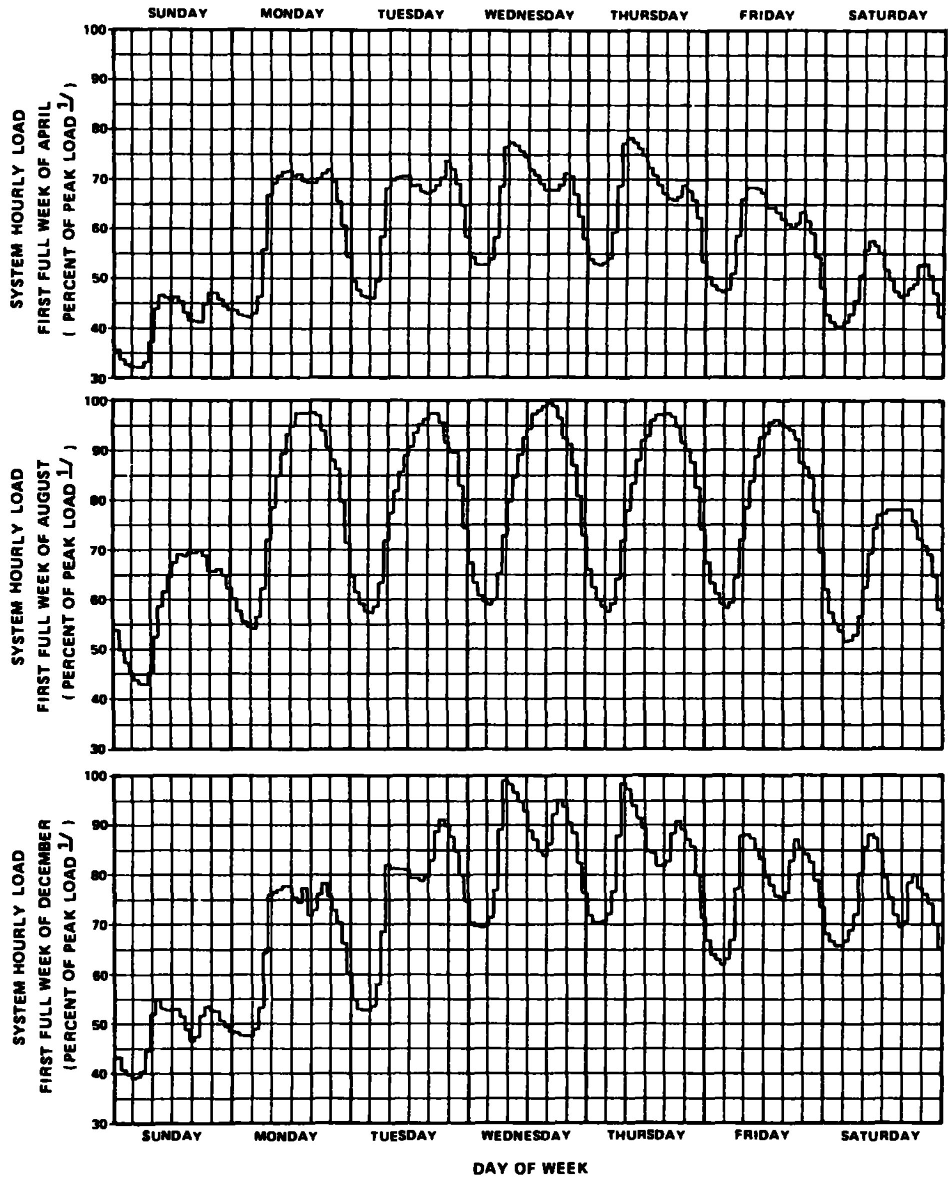
CONTRACT NO. DACW72 78 C-0017
DATE MARCH, 1979
EXHIBIT VII-5

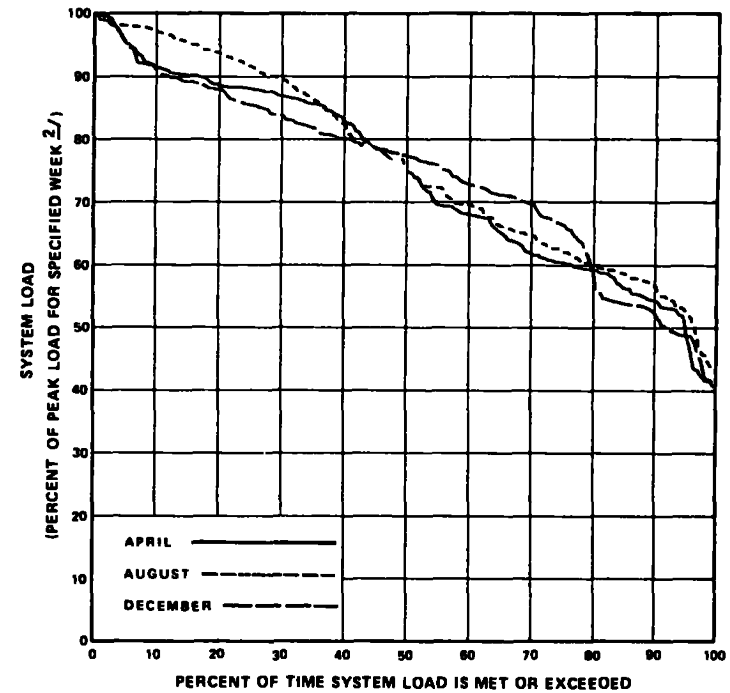
SERC
SYSTEM LOAD VARIATIONS (Cont'd)
1977

Representative Utilities or Power Groups	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
Virginia-Carolinas Sub-region										
Carolina Power & Light Company	66.5	74.9	96.1	77.6	88.9	72.4	5597	July 20	28,939	59.0
Duke Power Company	74.7	73.7	95.2	75.6	94.5	73.6	9450	Jan 17	51,240	61.9
South Carolina Public Service Authority	62.4	77.8	99.9	76.2	83.7	68.8	1161	July 20	5,785	56.9
Virginia Electric & Power Company	63.5	77.2	97.8	75.1	83.4	75.2	7902	July 21	37,982	54.9
Yadkin Inc.	99.3	94.7	96.3	97.4	98.6	97.4	216	Feb 1	1,789	94.6
Southern Companies Sub-Region										
Alabama Electric Cooperative	62.4	70.1	95.6	69.8	82.3	64.5	243.0	July 13	1,134	53.3
Crisp County Power Commission	60.0	68.4	87.4	69.7	85.9	60.5	40.5	Jan 19	181	51.0
Savannah Electric & Power Company	66.1	77.1	93.5	78.8	75.7	74.4	446.6	July 22	2,291	58.6
South Mississippi Electric Power Association	65.0	73.8	96.2	72.7	83.5	67.7	237	June 22	1,187	57.2
Southern Company System 2/	64.3	78.7	97.9	75.2	79.6	75.7	7,956	July 21	93,890	59.7

2/ Includes Alabama Power Co., Georgia Power Co., Gulf Power Co., and Mississippi Power Company.

SERC
SYSTEM LOAD VARIATIONS, 1977
SHEET 2 OF 2
DATE MARCH, 1979
EXHIBIT VII-5





NOTES.

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

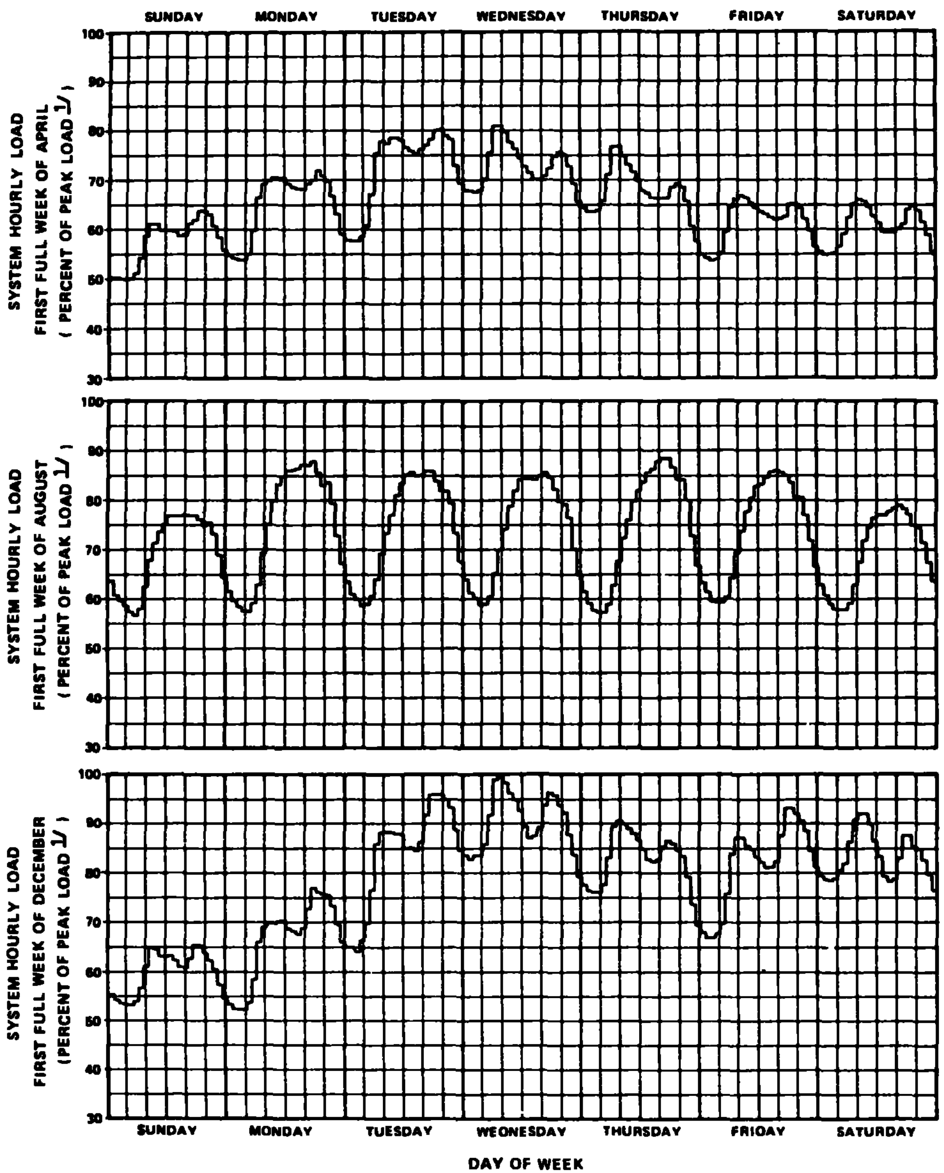
DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

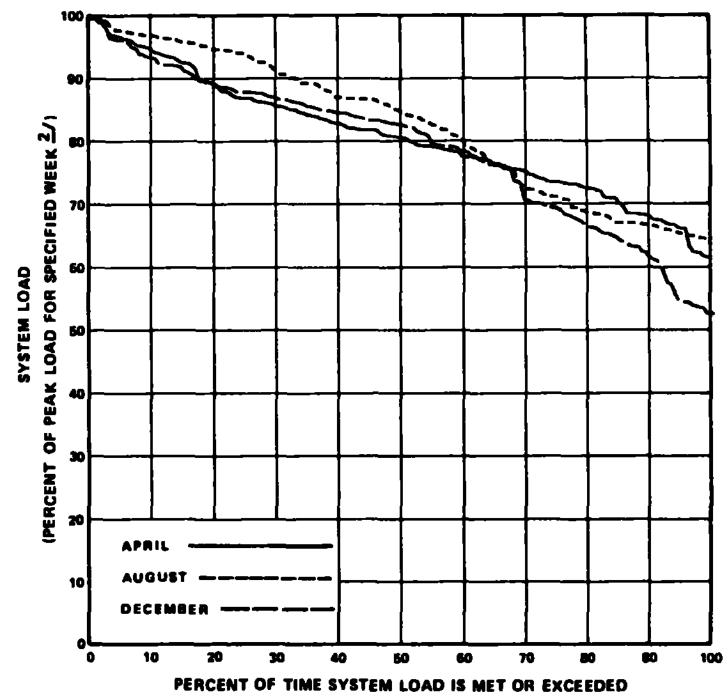
LOAD CURVES

REGION. SERC
SUB-REGION VACAR
UTILITY· DUPC
SHEET 1 OF 4

MARCH, 1979

VII-6





NOTES

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

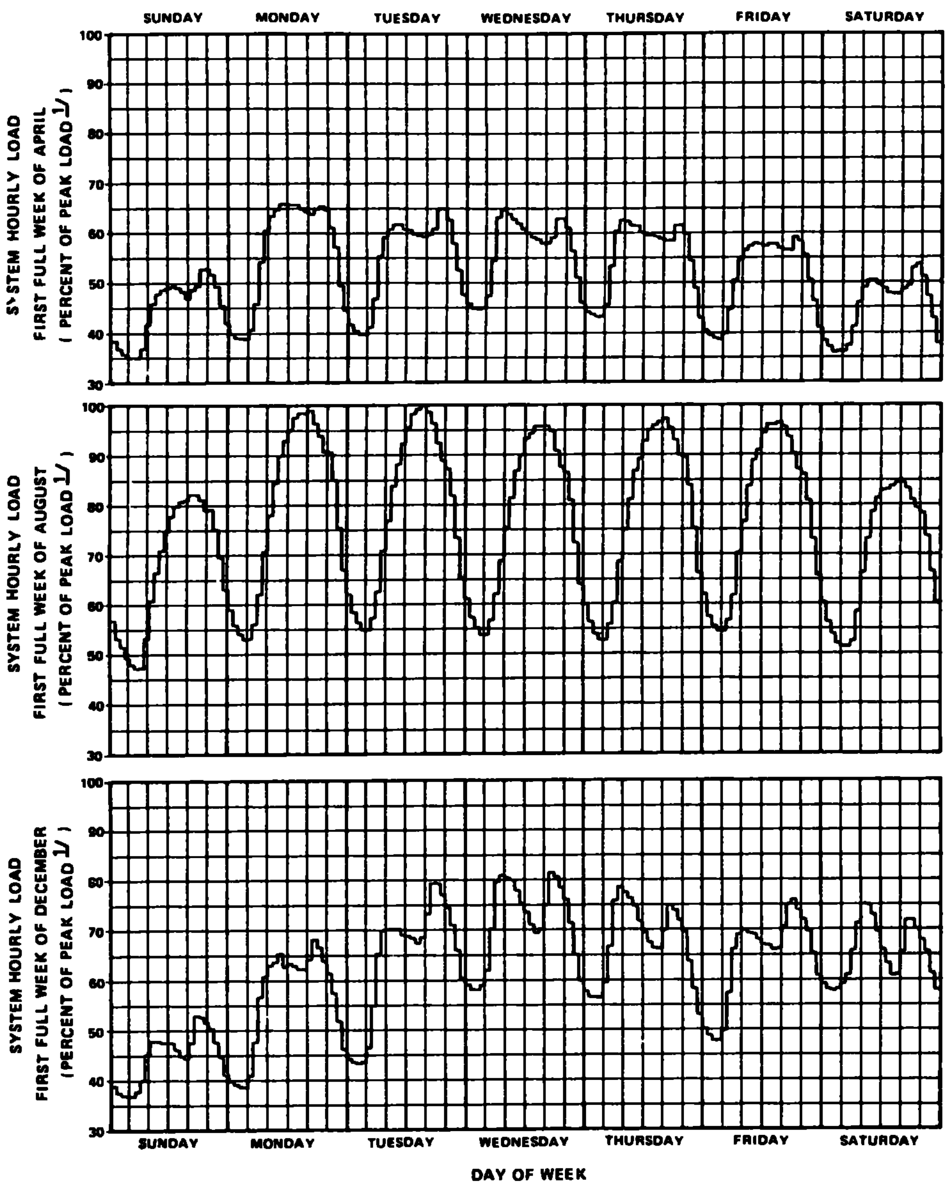
DEPARTMENT OF THE ARMY

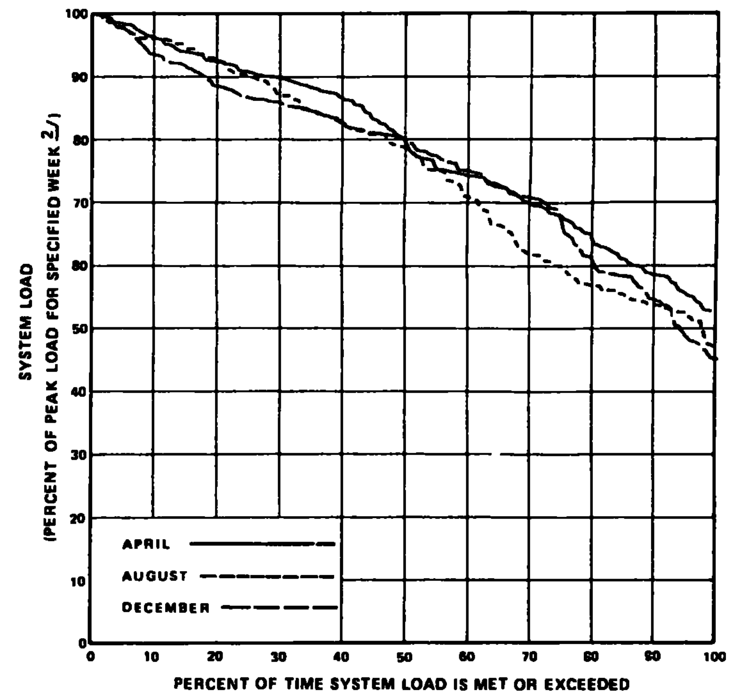
LOAD CURVES

REGION SERC
SUB-REGION TVA
UTILITY TVA
SHEET 2 OF 4

MARCH, 1979

EXHIBIT VII-6





NOTES

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

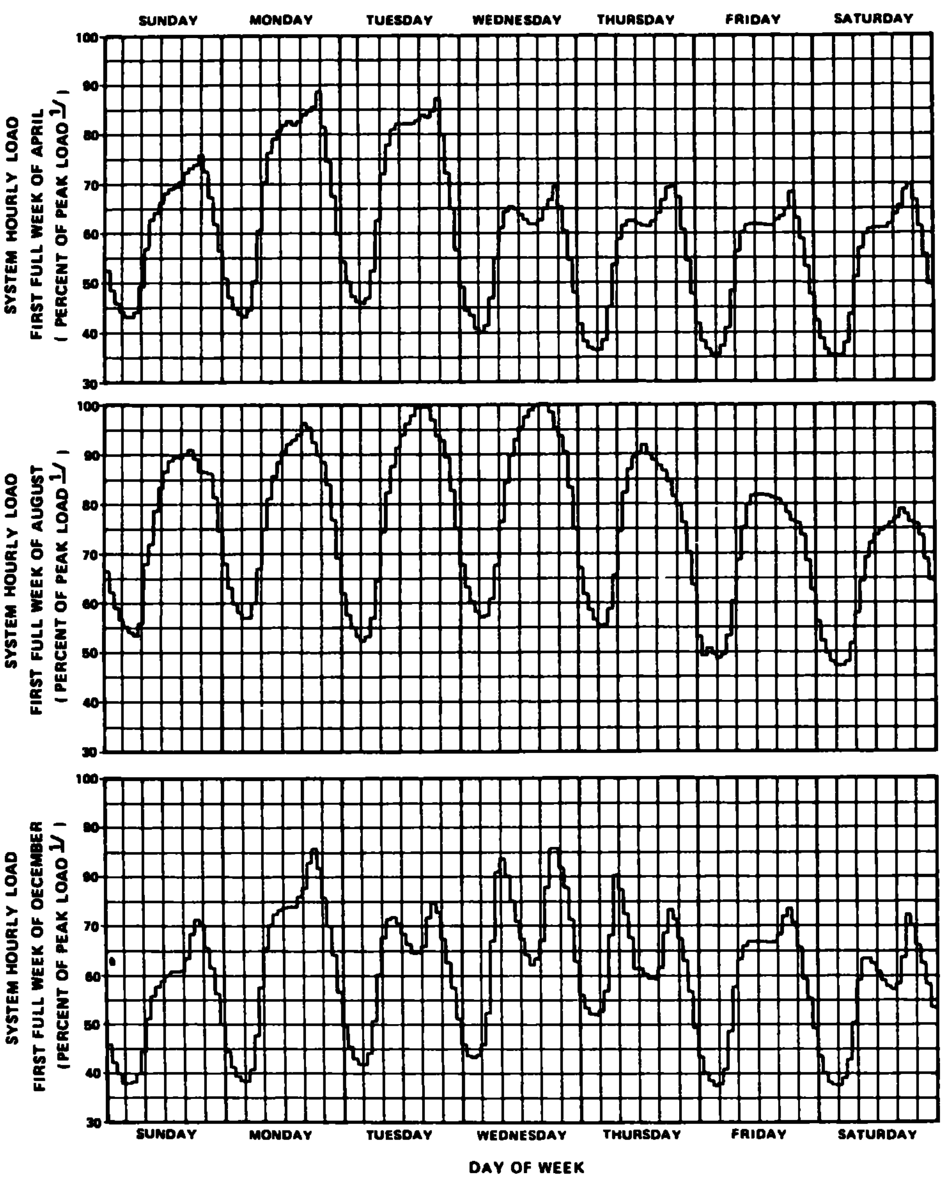
DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

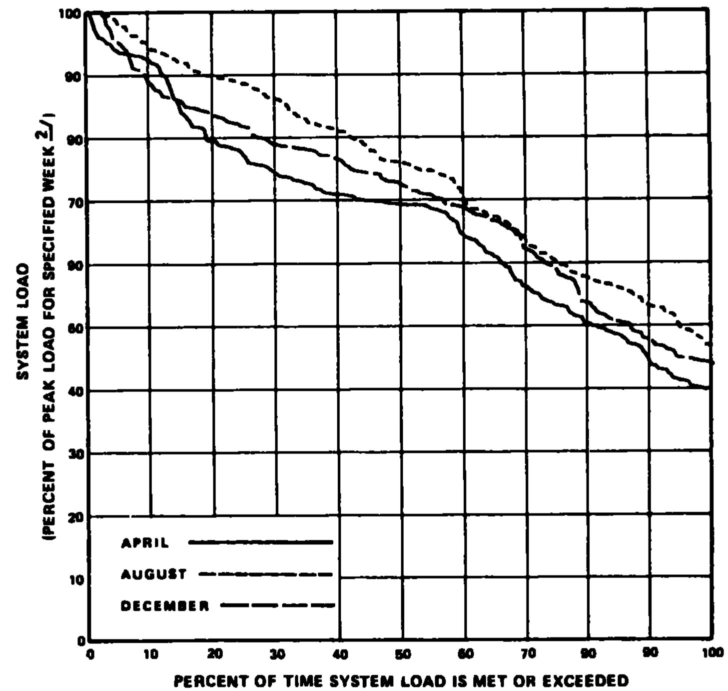
LOAD CURVES

REGION SERC
SUB-REGION SOUTHERN
UTILITY SOUTHERN
SHEET 3 OF 4

DATE MARCH, 1979

VII-6





NOTES.

1. PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER.

2. PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15(FOR 1977

LOAD CURVES

REGION. SERC
SUB–REGION. FLORIDA
UTILITY FLPL

SHEET 4 OF 4

MARCH 1979

VII–6

SERC
TENNESSEE VALLEY AND VIRGINIA-CAROLINAS SUB-REGIONS
EXISTING GENERATING CAPABILITIES BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Tennessee Valley Authority	MW	3,201	-	16,529	-	-	2,948	-	-	2,484	-	-	-	25,162
	%	12.7	-	65.7	-	-	11.7	-	-	9.9	-	-	-	100.0
Southeastern Power Administration	MW	-	-	-	-	-	704	-	-	-	-	-	-	704
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Tapoco, Inc.	MW	-	-	-	-	-	316.0	-	-	-	-	-	-	316
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Nantahala Power & Light Company	MW	-	-	-	-	-	92.0	-	-	-	-	-	-	92.0
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Tennessee Valley Sub-Region Total	MW	3,201	-	16,529	-	-	4,060	-	-	2,484	-	-	-	26,274
	%	12.2	-	62.9	-	-	15.5	-	-	9.4	-	-	-	100.0
Carolina Power & Light Company	MW	2,280	-	3,878	-	34	212	-	-	-	-	1,264	-	7,668
	%	29.7	-	50.6	-	0.4	2.8	-	-	-	-	16.5	-	100.0
Duke Power Company	MW	2,580	-	7,622	-	282	842	610	-	381	-	-	-	12,317
	%	21.0	-	61.9	-	2.3	0.7	5.0	-	3 1	-	-	-	100.0
Southeastern Power Administration	MW	-	-	-	-	-	515	-	-	-	-	-	-	515
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
South Carolina Public Service Authority	MW	-	-	1,050	92	-	124	-	-	150	-	-	-	1,416
	%	-	-	74.2	6.5	-	8.7	-	-	10.6	-	-	-	100.0
South Carolina Electric & Gas Company	MW	-	-	1,660	676	109	244	-	9	188	-	-	-	2,886
	%	-	-	57.5	23.4	3.8	8.5	-	0.3	6.5	-	-	-	100.0
Virginia Electric & Power Company	MW	1,550	-	2,960	3,499	-	326	-	-	550	-	-	-	8,885
	%	17.4	-	33.3	39.4	-	3.7	-	-	6.2	-	-	-	100.0
Yadkin, Inc.	MW	-	-	-	-	-	200	-	-	-	-	-	-	200
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Virginia-Carolinas Sub-Region Total	MW	6,410	-	17,170	4,267	425	2,463	610	9	1,269	-	1,264	-	33,887
	%	18.9	-	50.7	12.6	1.3	7.3	1.8	0.0	3.7	-	3.7	-	100.0

Source: Based on winter generating capability reported to the Department of Energy FERC (FPC) Order 383-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SERC
EXISTING GENERATING CAPABILITY
SHEET 1 OF 4

DATE MARCH, 1979 EXHIBIT VII-7

SERC
SOUTHERN COMPANIES SUB-REGION
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Alabama Electric Cooperative	MW	-	-	120	-	-	4	-	-	11	-	-	-	135
	%	-	-	88.9	-	-	3.0	-	-	8.1	-	-	-	100.0
Alabama Power Company	MW	807	29	4,178	39	-	1,139	-	-	103	-	-	-	6,295
	%	12.8	0.5	66.4	0.6	-	18.1	-	-	1.6	-	-	-	100.0
Crisp County Power Commission	MW	-	-	13	-	-	13	-	-	-	-	-	-	26
	%	-	-	50.0	-	-	50.0	-	-	-	-	-	-	100.0
Georgia Power Company	MW	757	-	8,308	367	-	456	-	-	1,141	-	5	-	11,034
	%	6.9	-	75.3	3.3	-	4.1	-	-	10.3	-	0.0	-	100.0
Gulf Power Company	MW	-	74	1,404	-	-	-	-	-	43	-	-	-	1,521
	%	-	4.9	92.3	-	-	-	-	-	2.8	-	-	-	100.0
Mississippi Power Company	MW	-	-	1,455	430	-	-	-	30	73	-	-	-	1,988
	%	-	-	73.2	21.6	-	-	-	1.5	3.7	-	-	-	100.0
Savannah Electric & Power Company	MW	-	-	-	388	-	-	-	-	62	-	-	-	450
	%	-	-	-	86.2	-	-	-	-	13.8	-	-	-	100.0
South Mississippi Elect. Po. Assoc.	MW	-	-	-	177	-	-	-	16	20	-	-	-	213
	%	-	-	-	83.1	-	-	-	7.5	9.4	-	-	-	100.0
Southeastern Power Administration	MW	-	-	-	-	-	1,141	278	-	-	-	-	-	1,419
	%	-	-	-	-	-	80.4	19.6	-	-	-	-	-	100.0
Southern Electric Generating Co.	MW	-	-	1,026	-	-	-	-	20	-	-	-	-	1,046
	%	-	-	98.1	-	-	-	-	1.9	-	-	-	-	100.0
Southern Companies Sub-Region Total	MW	1,564	103	16,504	1,401	-	2,753	278	66	1,453	-	5	-	24,127
	%	6.5	0.4	68.4	5.8	-	11.4	1.2	0.3	6.0	-	0.0	-	100.0

Source: Based on winter generating capability reported to the Department of Energy, FERC (CPC) Order 383-4, Docket R-362, April, 1978.

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THE NATIONAL HYDROPOWER STUDY

SERC
EXISTING GENERATING CAPABILITY
PAGE 2 OF 4

CONTRACT No. DACW72-78-C-0019
DATE MARCH, 1979
EXHIBIT VII-7

SERC

FLORIDA SUB-REGION

EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS

(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Florida Power & Light Company	MW	2,187	-	-	6,404	290	-	-	-	2,286	-	27	-	11,194
	%	19.5	-	-	57.2	2.6	-	-	-	20.4	-	0.3	-	100.0
Florida Power Corporation	MW	731	-	433	2,119	-	-	-	-	1,169	-	-	-	4,452
	%	16.4	-	9.7	47.6	-	-	-	-	26.3	-	-	-	100.0
Fort Pierce Utilities Auth.	MW	-	-	-	111	-	-	-	-	-	-	6	-	117
	%	-	-	-	94.9	-	-	-	-	-	-	5.1	-	100.0
Gainesville/Alachua County Regional Utilities Board	MW	12	-	-	165	-	-	-	-	97	-	1	-	275
	%	4.3	-	-	60.0	-	-	-	-	35.3	-	0.4	-	100.0
City of Homestead	MW	-	-	-	-	-	-	-	-	-	-	53	-	53
	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
Jacksonville Electric Authority	MW	-	-	-	1,591	-	-	-	-	546	-	-	-	2,137
	%	-	-	-	74.5	-	-	-	-	25.5	-	-	-	100.0
Lake Worth Utilities Authority	MW	-	77	-	-	-	-	-	-	32	-	10	-	119
	%	-	64.7	-	-	-	-	-	-	26.9	-	8.4	-	100.0
City of Lakeland	MW	-	-	-	324	-	-	-	-	62	-	6	-	392
	%	-	-	-	82.7	-	-	-	-	15.8	-	1.5	-	100.0
Orlando Utilities Commission	MW	13	-	-	706	-	-	-	-	32	-	1	-	752
	%	1.7	-	-	93.9	-	-	-	-	4.3	-	0.1	-	100.0
Seminole Electric Cooperative	MW	14	-	-	-	-	-	-	-	-	-	-	-	14
	%	100.0	-	-	-	-	-	-	-	-	-	-	-	100.0
City of Tallahassee	MW	11	-	73	445	-	-	-	-	-	-	-	-	529
	%	2.1	-	13.8	84.1	-	-	-	-	-	-	-	-	100.0
Tampa Electric Company	MW	-	-	1,581	718	-	-	-	-	158	-	-	-	2,457
	%	-	-	64.3	29.2	-	-	-	-	6.5	-	-	-	100.0
City of Vero Beach	MW	-	-	-	122	-	-	-	-	-	-	-	-	122
	%	-	-	-	100.0	-	-	-	-	-	-	-	-	100.0
Florida Sub-Region	MW	2,968	77	2,087	12,705	290	-	-	-	4,382	-	104	-	22,613
	%	13.1	0.3	9.2	56.2	1.3	-	-	-	19.4	-	0.5	-	100.0

Source: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April, 1978.

HARZA ENGINEERING COMPANY
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SERC

EXISTING GENERATING CAPABILITY

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CONTRACT NO. DACW72-78-C-0013

DATE MARCH, 1979

EXHIBIT VII-7

SERC - SUMMARY
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Florida Sub-Region Total	MW	2,968	77	2,087	12,705	290	-	-	-	4,382	-	104	-	22,613
	%	13.1	0.3	9.2	56.2	1.3	-	-	-	19.4	-	0.5	-	100.0
Southern Companies Sub-Region Total	MW	1,564	103	16,504	1,401	-	2,753	278	66	1,453	-	5	-	24,127
	%	6.5	0.4	68.4	5.8	-	11.4	1.2	0.3	6.0	-	0.0	-	100.0
Tennessee Valley Sub-Region Total	MW	3,201	-	16,529	-	-	4,060	-	-	2,484	-	-	-	26,274
	%	12.5	-	64.6	-	-	15.5	-	-	9.4	-	-	-	100.0
Virginia-Carolinas Sub-Region Total	MW	6,410	-	17,170	4,267	425	2,463	610	9	1,269	-	1,264	-	33,887
	%	18.9	-	50.7	12.6	1.3	7.3	1.8	0.0	3.7	-	3.7	-	100.0
SERC TOTAL	MW	14,143	180	52,290	18,373	715	9,276	888	75	9,588	-	1,373	-	106,901
	%	13.2	0.2	48.9	17.2	0.6	8.7	0.8	0.1	9.0	-	1.3	-	100.0

SOURCE: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

SERC
EXISTING GENERATING CAPABILITY
SHEET 4 OF 4
MARCH, 1979
EXHIBIT VII-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND SWPP REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **SWPP**	
CONTRACT NO DACW72 – 78 – C – 0013 DATE MARCH, 1979	EXHIBIT VIII–1

SWPP - REPORTING UTILITIES

Letter Code	Sub-Region
	GROUP A
	Members of SWPP:
ALEX	Alexandria Light & Power Department[1/]
AREC	Arkansas Electric Cooperative Corporation
CAJN	Cajun Electric Power Cooperative, Inc.
CELE	Central Louisiana Electric Company, Inc.
GUSU	Gulf States Utilities Company
LAFA	Lafayette, Louisiana Utility System
MSUI	Middle South Utilties, Inc.
ARPL	Arkansas Power & Light Company
ARMP	Arkansas-Missouri Power Company
LOPL	Louisiana Power & Light Company
MIPO	Mississippi Power & Light Company
NEOP	New Orleans Public Service Inc.
	GROUP B
	Members of SWPP:
GRRD	Grand River Dam Authority
OKGE	Oklahoma Gas and Electric Company
PSOK	Public Service Company of Oklahoma
SOEP	Southwestern Electric Power Company
SWPA	Southwestern Power Administration
SWPS	Southwestern Public Service Company
WEFA	Western Farmers Electric Cooperative
	Non-Members of SWPP:
NEME	New Mexico Electric Service Company[2/] (Subsidiary of SWPS)
	GROUP C
	Members of SWPP:
KACY	Board of Public Utilities, Kansas City, KA
CEKP	Central Kansas Power Company, Inc.
CHAN	Chanute Municipal Utilities
INDN	City Power & Light Independence, MO
COFF	Coeffeyville Municipal Water & Light Department
EMDE	The Empire District Electric Company
KACP	Kansas City Power & Light Company
KAGE	Kansas Gas and Electric Company
KAPL	The Kansas Power & Light Company
MIPU	Missouri Public Service Company
STJO	St. Joseph Light & Power Company

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **SWPP** **LIST OF UTILITIES** **PAGE 1 OF 2**	
CONTRACT NO DACW72-78-C-0013 DATE MARCH, 1979	EXHIBIT VIII-2

SWPP - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
	GROUP C (Cont'd)
	Members of SWPP (Cont'd)
SUNC	Sunflower Electric Cooperative
WINF	Winfield, Kansas, Municipal Light & Water
CTKS	Western Power Division, Central Telephone & Utilities Corporation
	GROUP D
	Members of SWPP:
SPRM	City Utilities, Springfield, MO
	GROUP E
	Non-members of WWPP:
HOUM	City of Houma, LA
JONE	Jonesboro (AR) City Water & Light
PONC	Ponca City (OK) Water & Light
OTTA	Ottawa (KA) Water & Light
RUST	City of Ruston, LA

1/ Application for membership being processed.

2/ Non-Member. System operated (and reported) by SWPS

NOTE:

The following member systems will be included in reports by contiguous councils as follows:

Associated Electric Cooperative, Inc.	MAIN
Missouri Utilities Company	MAIN
Missouri Power & Light Company	MAIN
Missouri Edison Company	MAIN
West Texas Utilities Company	ERCOT

Source: Southwest Power Pool Coordinated Regional Bulk Power Supply Programs 1978-1997, A Report to the Economic Regulatory Administration, Department of Energy, April 1, 1978.

HARZA ENGINEERING COMPANY
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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SWPP

LIST OF UTILITIES

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH, 1979

EXHIBIT VIII-2

SWPP

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate - %: 1 yr	Annual Energy: Average Annual Growth Rate - %: 5 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-%: 1 yr	Peak Demand: Average Annual Growth Rate-%: 5 yr	Annual Load Factor-%
1970	98.8[1/]	-	-	20.1	-	-	56.0
1971	109.0[1/]	10.3	-	22.2	10.1	-	56.1
1972	134.8[1/]	23.7	-	27.6	24.2	-	55.7[2/]
1973	139.9[1/]	3.7	-	29.4	6.6	-	54.4
1974	141.4	1.1	-	32.1	9.2	-	50.3
1975	154.2	9.1	9.3	32.2	0.4	9.9	54.7
1976	161.8	4.9	8.2	33.8	4.9	8.8	54.5[2/]
1977	179.5	11.0	5.9	36.8	9.1	5.9	55.6

1/ Estimated by SWPP using load factors.

2/ Load factor based on 8784 hours to reflect leap year.

SOURCE: Letter from B.C. Husley of SWPP.

SWPP
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

Representative Utilities	RESIDENTIAL 1970	1971	1972	1973	1974	1975	1976	1977
Central Louisiana Electric Co.,Inc	9 9	9 0	13 7	7.9	0.1	8.1	4.6	16 0
Gulf States Utilities Co.	NA	NA	NA	NA	NA	NA	NA	14.1
Kansas City Power and Light Co.	12.3	6.1	6 3	8.0	(2.0)	11.1	(4 6)	4.1
Kansas Gas and Electric Co	12.7	0.7	7.3	8.7	2.5	12.4	2.2	6.0
Kansas Power and Light Co.	12 9	5.8	8 0	8.7	2.9	9.8	(0.9)	NA
Board of Public Utilities, Kansas City	NA	NA	NA	NA	(4.1)	13.8	0.1	2.4
Middle South Utilities, Inc.	11.3	10.0	16 7	9.5	(2.2)	8.4	2.4	NA
Missouri Public Service Co	NA	NA	NA	NA	NA	NA	NA	NA
Okalahoma Gas and Electric Co	NA	NA	NA	NA	NA	NA	NA	NA
Public Service Co of Okalahoma	13.2	4.4	16 0	4.7	NA	NA	NA	NA
Southwestern Electric Power Co.	8.6	7.5	14 8	6.3	2.3	12 8	(0 3)	18.4
Southwestern Power Adminsiration	NA	NA	NA	NA	NA	NA	NA	NA
Southwestern Public Service Co.	16.0	15.0	15.0	15.0	15.0	15.0	14.0	14.0
Western Farmers Electric Cooperative	NA	NA	NA	NA	NA	NA	NA	NA

Representative Utilities	COMMERCIAL 1970	1971	1972	1973	1974	1975	1976	1977
Central Louisiana Electric Co.,Inc	7 0	8.2	12 7	7 3	3.5	9 0	5 8	13 2
Gulf States Utilities Co.	NA	NA	NA	NA	NA	NA	NA	10 0
Kansas City Power and Light Co.	5.4	3 3	7.8	7 4	(1 0)	7 3	1.5	6.6
Kansas Gas and Electric Co	11.1	4 3	8.1	5.9	(0.2)	10.9	4 4	5 8
Kansas Power and Light Co.	12.0	7.7	8.4	3 3	(2 7)	9 6	3 3	NA
Board of Public Utilities, Kansas City	NA	NA	NA	NA	2 5	17 8	3 1	7 0
Middle South Utilities, Inc.	9.8	9.5	11.9	9.1	0.1	8.4	4 8	NA
Missouri Public Service Co	NA	NA	NA	NA	NA	NA	NA	NA
Okalahoma Gas and Electric Co	NA	NA	NA	NA	NA	NA	NA	NA
Public Service Co of Okalahoma	7.9	7.7	11.6	5.1	NA	NA	NA	NA
Southwestern Electric Power Co.	8.1	8.3	11 7	8 1	2 0	12 1	5.9	11.5
Southwestern Power Adminsiration	NA	NA	NA	NA	NA	NA	NA	NA
Southwestern Public Service Co.	17.0	16.0	17.0	16 0	16 0	18 0	17 0	17.0
Western Farmers Electric Cooperative	NA	NA	NA	NA	NA	NA	NA	NA

Representative Utilities	INDUSTRIAL 1970	1971	1972	1973	1974	1975	1976	1977
Central Louisiana Electric Co.,Inc	65 6	8 7	10 4	9 4	1 9	8.3	9.8	8 4
Gulf States Utilities Co.	NA	NA	NA	NA	NA	NA	NA	11.2
Kansas City Power and Light Co.	4.3	6 2	7 4	5 5	(1 7)	(9 4)	12 0	8 4
Kansas Gas and Electric Co	0.2	0.8	5.0	8.4	9 2	1 5	3.7	4.9
Kansas Power and Light Co.	(0.1)	2.5	6.6	8 2	8 6	1 4	3.9	NA
Board of Public Utilities, Kansas City	NA	NA	NA	NA	1 5	(3.0)	9.1	4.7
Middle South Utilities, Inc.	3.6	6 8	12 4	7.5	3.0	(9.0)	23.6	NA
Missouri Public Service Co	NA	NA	NA	NA	NA	NA	NA	NA
Okalahoma Gas and Electric Co	NA	NA	NA	NA	NA	NA	NA	NA
Public Service Co of Okalahoma	11.0)	7.7	19 2	8 7	NA	N.	NA	NA
Southwestern Electric Power Co.	5.0	8.7	10 8	9 2	2.6	3 8	10.5	12 5
Southwestern Power Adminsiration	NA	NA	NA	NA	NA	NA	NA	NA
Southwestern Public Service Co.	42 0	43.0	42 0	43.0	42.0	44.0	44.0	44.0
Western Farmers Electric Cooperative	NA	NA	NA	NA	NA	NA	NA	NA

Representative Utilities	TOTAL 1970	1971	1972	1973	1974	1975	1976	1977
Central Louisiana Electric Co.,Inc	27.2	8 3	12 2	8 4	1 4	8 3	7.0	12.3
Gulf States Utilities Co.	NA	NA	NA	NA	NA	NA	NA	11 [illegible]
Kansas City Power and Light Co.	6.6	5.0	7 2	7 0	(1.5)	3 6	2 2	6 3
Kansas Gas and Electric Co	6 3	1 6	6 4	7.9	4 8	7 0	3.4	5.4
Kansas Power and Light Co.	7 7	5 4	7.6	6.3	2.1	6.5	1.9	NA
Board of Public Utilities, Kansas City	NA	NA	NA	NA	0.5	6 3	5 2	4.9
Middle South Utilities, Inc.	7 3	8 4	13 8	8.5	0.6	0 4	11 8	NA
Missouri Public Service Co	NA	NA	NA	NA	NA	NA	NA	NA
Okalahoma Gas and Electric Co	NA	NA	NA	NA	NA	NA	NA	NA
Public Service Co of Okalahoma	6 8	6.4	15.7	6 1	NA	NA	NA	NA
Southwestern Electric Power Co.	6 9	8 2	12 4	7 9	2 4	8 8	5 6	14 2
Southwestern Power Adminsiration	NA	NA	NA	NA	NA	NA	NA	NA
Southwestern Public Service Co.	2.5	10 0	6 3	7.5	3.1	1.3	11.9	15 0
Western Farmers Electric Cooperative	NA	NA	NA	NA	NA	NA	NA	NA

Source. the 1977 annual report for each utility in the council

SWPP

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

MARCH, 1979

VIII – 4

SWPP
SYSTEM LOAD VARIATIONS 1/
1977

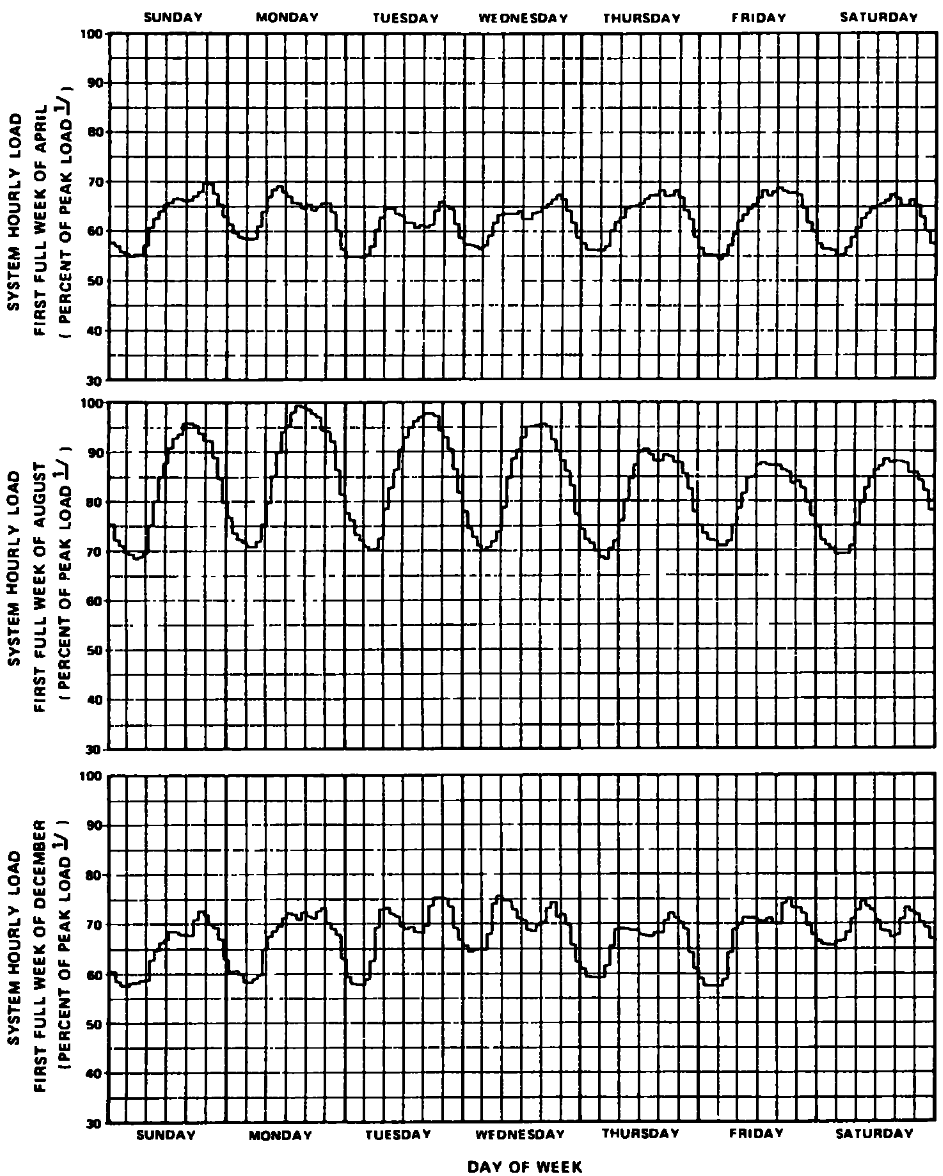
Representative Utilities	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
Middle South Utilities, Inc.	60.4	82.6	98.7	76.4	69.7	82.6	9780	July 14	51,085	59.6
Gulf States Utilities Co.	67.3	89.1	96.0	83.0	72.9	88.6	4657	Jul6 25	27,899	67.2
Oklahoma Gas & Electric Co.	51.8	79.3	96.6	69.5	66.9	79.2	3585	July 25	15,747	50.1
Kansas City Power & Light Co.	54.0	75.9	100.0	63.9	63.4	77.8	1939	Aug 8	8,276	48.7
Public Service Company of Oklahoma	51.2	79.2	94.5	69.7	64.7	80.5	2405	July 25	10,628	50.4
Southeastern Public Service Company	72.2	88.1	100.0	75.5	69.9	85.5	2150	Aug 8	11,487	61.2
Southwestern Electric Power Company	50.8	79.7	95.8	95.8	62.4	62.4	2404	July 25	10,835	51.4
The Kansas Power & Light Company	56.6	74.7	96.7	63.5	72.1	77.1	1517	July 20	6,557	49.3
Central Louisiana Electric Company, Inc.	54.9	80.2	95.3	74.2	63.2	79.9	978	July 25	4,703	71.9
Kansas Gas and Electric Company	58.7	79.1	97.5	66.7	72.1	79.7	1441	July 20	6,789	53.8
Missouri Public Service Company	49.3	74.6	100.0	58.7	63.4	76.8	604	Aug 8	2,365	44.7
Western Farmers Electric Cooperative	51.6	79.5	74.3	74.7	100.0	72.0	506	Dec 9	2,165	48.8
Board of Public Utilities, Kansas City, Kansas	65.7	76.4	100.0	69.1	74.8	78.9	394.5	Aug 8	1,991	57.6

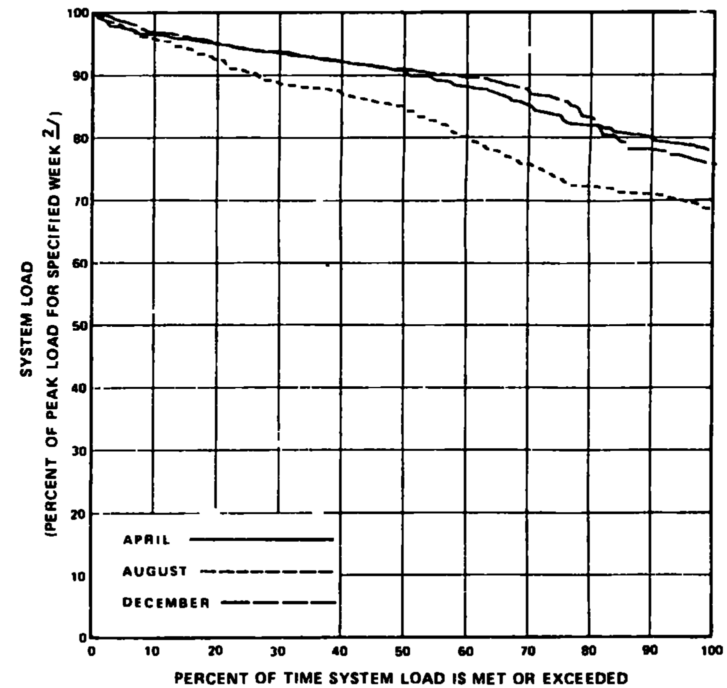
1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12

HARZA

SWPP
SYSTEM LOAD VARIATIONS, 1977

DATE MARCH, 1979
EXHIBIT VIII – 5





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL AUGUST AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION SWPP

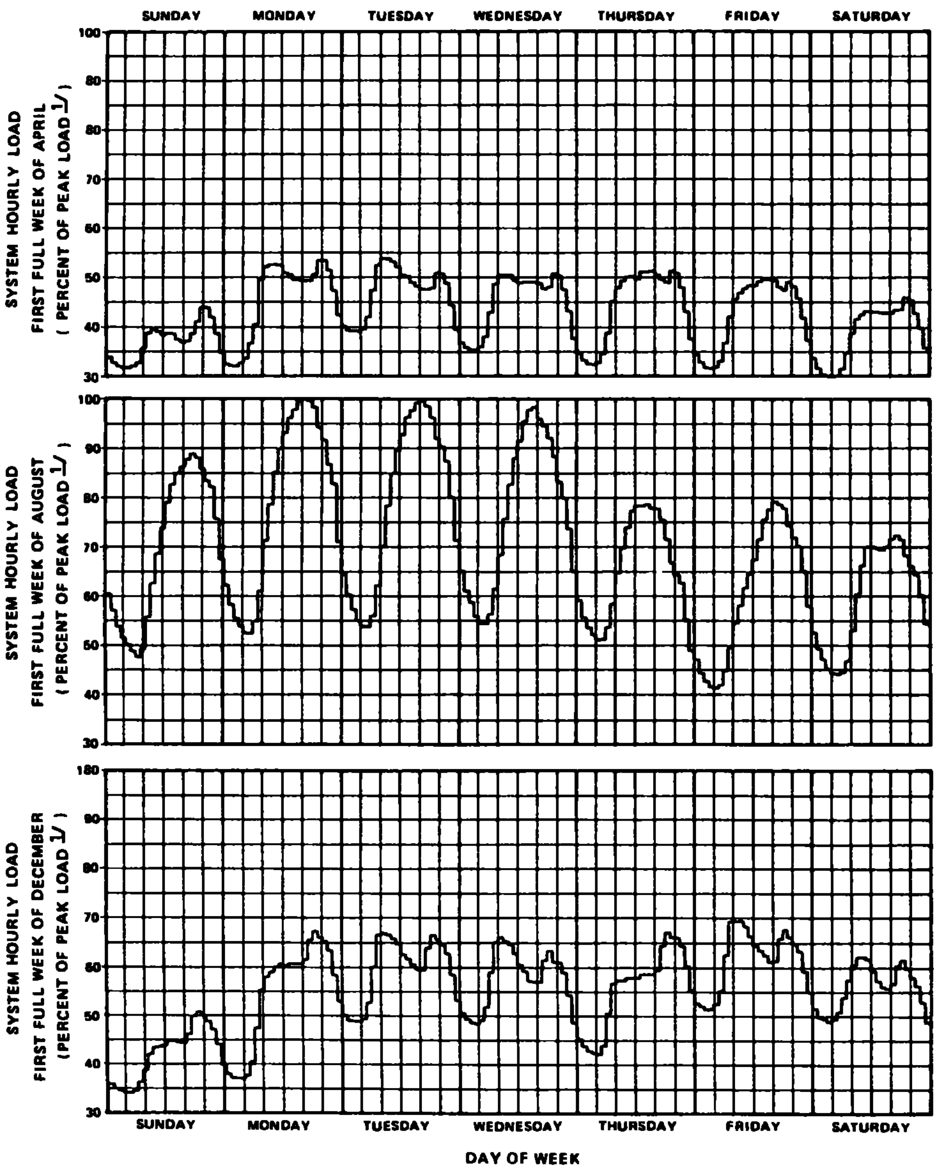
SUB-REGION SWPP

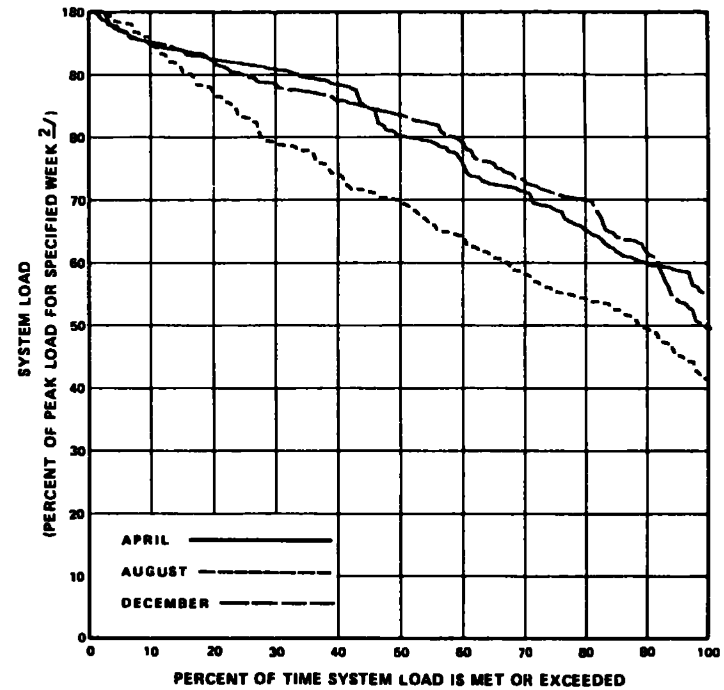
UTILITY GUSU

SHEET 1 OF 4

MARCH, 1979

VIII-6





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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

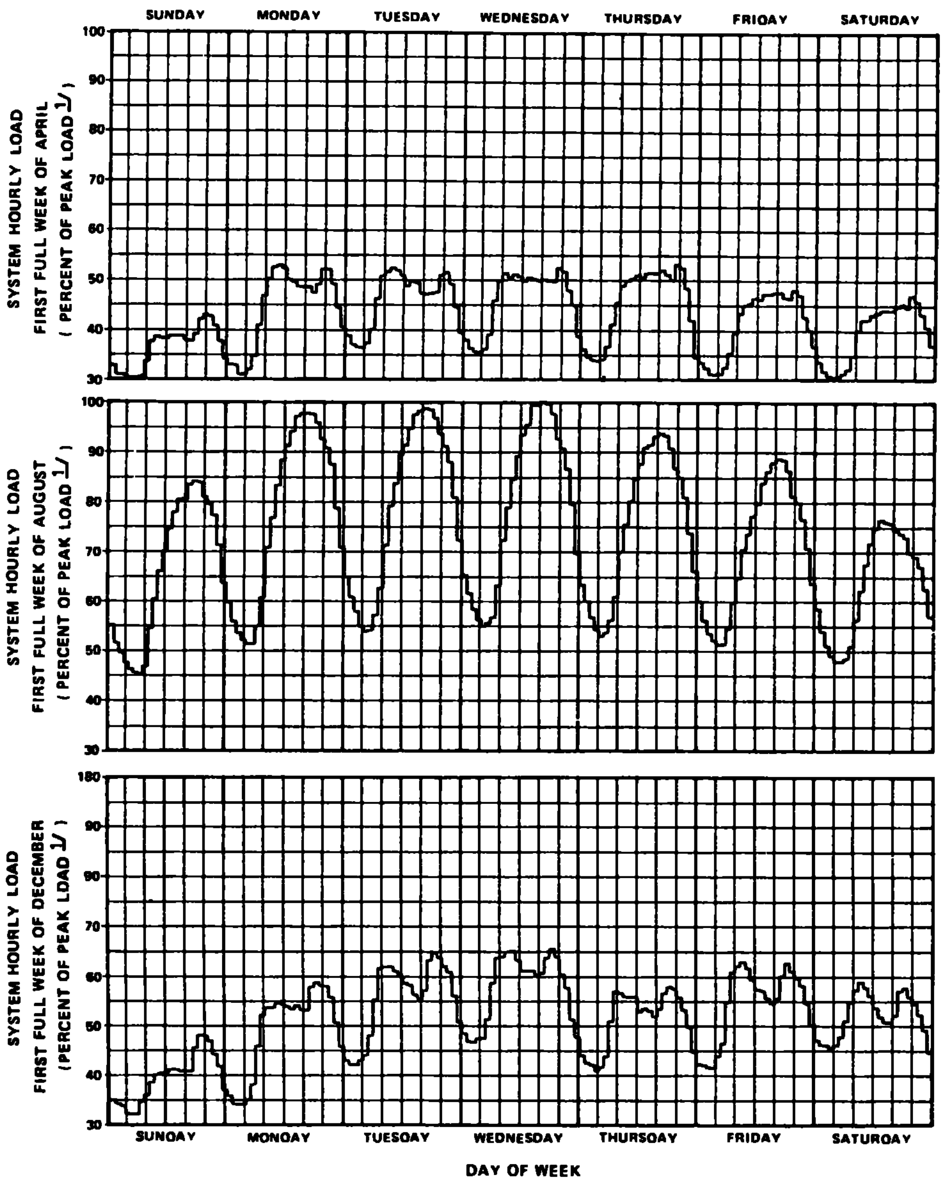
LOAD CURVES

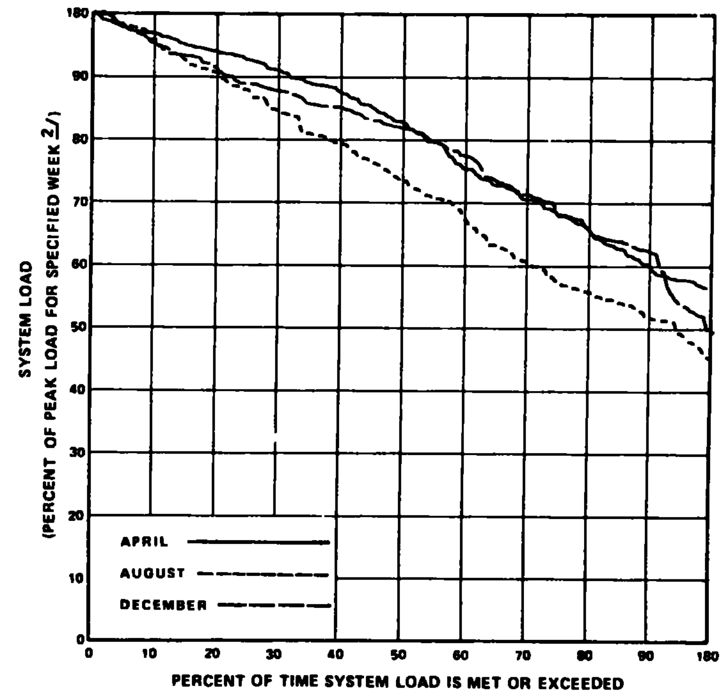
REGION SWPP
SUB-REGION SWPP
UTILITY OKGE

SHEET 2 OF 4

MARCH 1979

VIII-6





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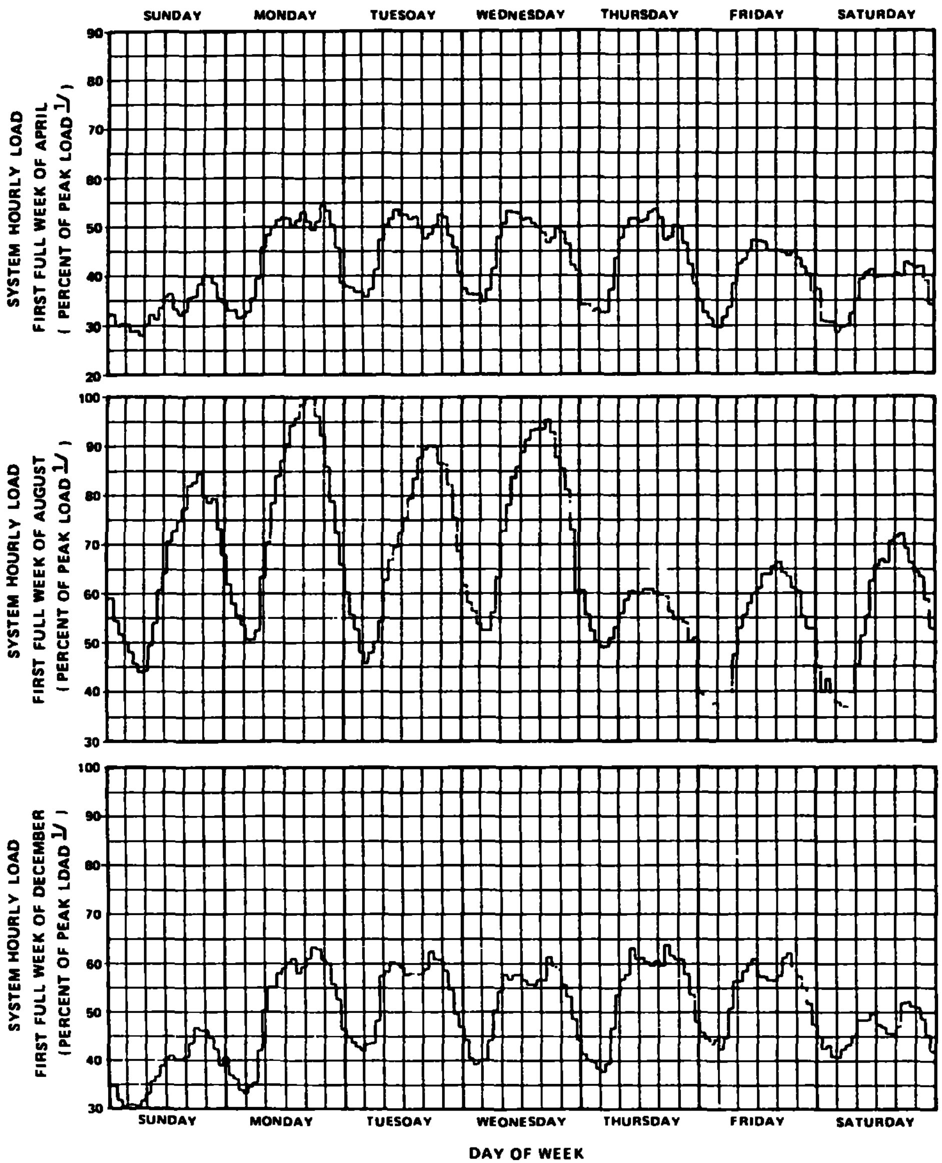
SOURCE

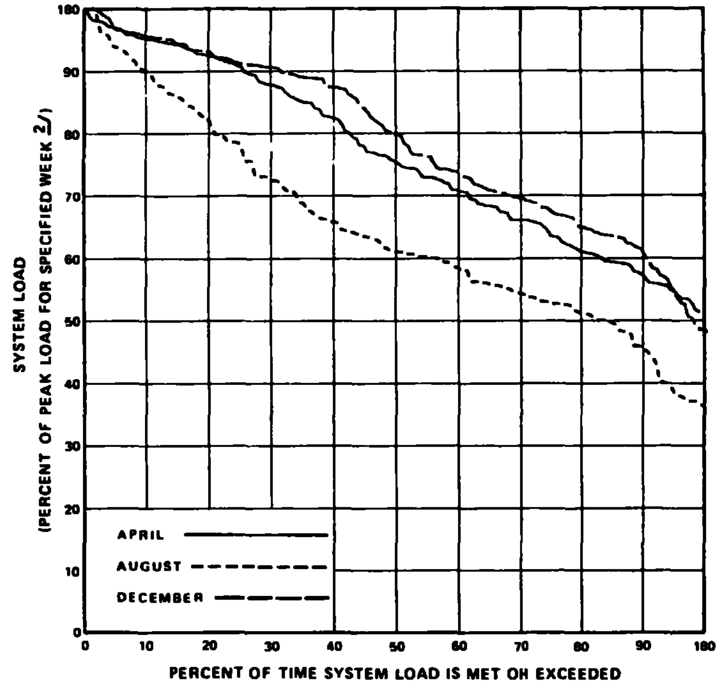
DATA OBTAINED FROM FERC FORM NO. 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES
REGION: SWPP
SUB-REGION SWPP
UTILITY SOEP
SHEET 3 OF 4

MARCH, 1979

VIII-6





NOTES

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

DEPARTMENT OF THE ARMY

LOAD CURVES

REGION SWPP
SUB-REGION SWPP
UTILITY KACP
SHEET 4 OF 4

MARCH 1979

EXHIBIT VIII-6

SWPP
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Alexandria Light &	MW	-	175	-	-	-	-	-	-	-	-	-	-	175
Power Department	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Arkansas Electric	MW	-	134	-	-	-	-	-	-	-	-	-	-	134
Cooperative Corp.	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Cajun Electric Power	MW	-	460	-	-	-	-	-	-	-	-	-	-	460
Cooperative, Inc.	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Central Louisiana	MW	-	1,323	-	-	-	-	-	-	-	-	-	-	1,323
Electric Co., Inc.	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Gulf State Utilities	MW	-	3,406	-	2,116	-	-	-	-	-	-	-	-	5,522
Company	%	-	61.7	-	38.3	-	-	-	-	-	-	-	-	100.0
Lafayette, Louisiana	MW	-	377	-	-	-	-	-	-	-	-	-	-	377
Utility System	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Middle South	MW	836	8,199	-	1,583	421	69	-	15	71	-	6	-	11,200
Utilities, Inc.	%	7.5	73.2	-	14.1	3.8	0.6	-	0.1	0.6	-	0.0	-	100.0
Grand River Dam	MW	-	50	-	-	-	199	260	-	-	-	-	-	509
Authority	%	-	9.8	-	-	-	39.1	51.1	-	-	-	-	-	100.0
Oklahoma Gas and	MW	-	3,182	-	-	410	-	-	-	-	-	8	-	3,600
Electric Company	%	-	88.4	-	-	11.4	-	-	-	-	-	0.2	-	100.0
Public Service Co.	MW	-	2,488	-	-	230	-	-	-	168	-	26	-	2,912
of Oklahoma	%	-	85.4	-	-	7.9	-	-	-	5.8	-	0.9	-	100.0
Southwestern Electric	MW	-	1,801	528	-	-	-	-	-	40	-	-	-	2,369
Power Company	%	-	76.0	22.3	-	-			-	1.7	-	-	-	100.0
Southwestern Power	MW	-	181	-	-	-	1,923	28	-	-	-	-	-	2,132
Administration	%	-	8.5	-	-	-	90.2	1.3	-	-	-	-	-	100.0
Southwestern Public	MW	-	2085	317	-	53	-	-	120	-	-	-	12 1/	2,587
Service Company	%	-	80.6	12.3	-	2.1	-	-	4.6	-	-	-	0.4	100.0
Western Farmers	MW	-	419	-	-	300	-	-	-	-	2	2	-	723
Electric Cooperative	%	-	55.6	-	-	43.8	-	-	-	-	0.3	0.3	-	100.0
Board of Public	MW	-	96	372	-	-	-	-	-	131	-	-	-	599
Utilities, KC,KA	%	-	16.0	62.1	-	-	-	-	-	21.9	-	-	-	100.0
Centra. Kansas Power	MW	-	60	-	-	-	-	-	16	-	5	3	-	84
Company, Inc.	%	-	71.4	-	-	-	-	-	19.0	-	6.0	3.6	-	100.0

1/ Expander Turbine

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO, ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SWPP

EXISTING GENERATING CAPABILITY

PAGE 1 OF 2

CONTRACT NO. DACW72 78 C-0017

DATE MARCH, 1979

EXHIBIT VIII-7

SWPP
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
City Power & Light, Independence Co.	MW	-	108	-	-	-	-	-	19	137	-	-	-	264
	%	-	40.9	-	-	-	-	-	7.2	51.9	-	-	-	100.0
The Empire District Electric Company	MW	-	-	289	49	15	16	-	-	-	-	-	-	369
	%	-	-	78.3	13.3	4.1	4.3	-	-	-	-	-	-	100.0
Kansas City Power & Light Company	MW	-	-	2,871	80	-	-	-	-	398	-	-	-	3,349
	%	-	-	85.7	2.4	-	-	-	-	11.9	-	-	-	100.0
Kansas Gas and Electric Company	MW	-	1,106	48	-	-	-	-	-	-	-	3	-	1,157
	%	-	95.6	4.2	-	-	-	-	-	-	-	0.2	-	100.0
The Kansas Power & Light Company	MW	-	1,211	-	-	-	-	-	248	105	-	-	-	1,564
	%	-	77.4	-	-	-	-	-	15.8	6.7	-	-	-	100.0
Missouri Public Service Company	MW	-	59	463	-	-	-	-	-	180	-	-	30 1/	732
	%	-	8.1	63.2	-	-	-	-	-	24.6	-	-	4.1	100.0
St. Joseph Light & Power Company	MW	-	95	117	-	70	-	-	-	-	-	-	-	282
	%	-	33.7	41.5	-	24.8	-	-	-	-	-	-	-	100.0
Sunflower Electric Cooperative	MW	-	113	-	-	-	-	-	62	-	13	-	-	188
	%	-	60.1	-	-	-	-	-	33.0	-	6.9	-	-	100.0
Western Power Division Central Tele & Util. Corporation	MW	-	379	-	-	-	-	-	8	75	-	16	-	478
	%	-	79.3	-	-	-	-	-	1.7	15.7	-	3.3	-	100.0
City Utilities Springfield Mo.	MW	-	274	195	-	-	-	-	-	15	-	-	-	484
	%	-	56.6	40.3	-	-	-	-	-	3.1	-	-	-	100.0
City of Houma, LA	MW	-	80	-	-	-	-	-	8	-	17	-	-	105
	%	-	76.2	-	-	-	-	-	7.6	-	16.2	-	-	100.0
Jonesboro (AR) City Water & Light	MW	-	-	-	20	-	-	-	-	-	-	-	-	20
	%	-	-	-	100.0	-	-	-	-	-	-	-	-	100.0
Ponca City (OK) Water & Light	MW	-	60	-	-	-	-	-	-	-	-	27	-	87
	%	-	69.0	-	-	-	-	-	-	-	-	31.0	-	100.0
Ottawa, (KA) Water & Light	MW	-	7	-	-	10	-	-	-	-	7	-	-	24
	%	-	29.2	-	-	41.7	-	-	-	-	29.1	-	-	100.0
City of Ruston, LA	MW	-	81	-	-	-	-	-	-	-	1	1	-	83
	%	-	97.6	-	-	-	-	-	-	-	1.2	1.2	-	100.0
SWPP Total	MW	836	28,009	5,200	3,848	1,509	2,207	288	496	1,320	45	92	42	43,892
	%	1.9	63.9	11.8	8.8	3.4	5.0	0.7	1.1	3.0	0.1	0.2	0.1	100.0

1/ Jet Engine - Natural Gas

Source: Based on summer generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

SWPP
EXISTING GENERATING CAPABILITY
PAGE 2 OF 2

DATE MARCH 1979 EXHIBIT VIII-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND ERCOT REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ERCOT**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT IX-1

ERCOT - ELECTRIC UTILITIES

Letter Code

Reporting Members of ERCOT:

AUST	City of Austin Electric Utilities
CEPL	Central Power & Light Company
DAPL	Dallas Power & Light Company
HOLP	Houston Lighting & Power Company
LOCR	Lower Colorado River Authority
SAAN	City of San Antonio Public Service
ST&M	South Texas and Medina Electric Cooperatives, Pool
SOTE	South Texas Electric Cooperative, Inc.
MECI	Medina Electric Cooperative, Inc.
TEES	Texas Electric Service Company
TEPL	Texas Power & Light Company
TMPP	Texas Municipal Power Pool
BRYN	City of Bryan
BREP	Brazos Electric Power Cooperative, Inc.
DENT	City of Denton
GARL	City of Garland
GRUD	City of Greenville
WETU	West Texas Utilities Company

Source: "Report to the U.S. Department of Energy on Coordinated Bulk Power Supply Programs," FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

Other Members of ERCOT:

Cooperatives:

B-K
Barlett
Belfalls
Bluebonnett
Cap Rock
Comache County
Concho Valley
Deep East Texas
Denton County
DeWitt County
Dickens County
Fannin County

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ERCOT** **LIST OF UTILITIES** **SHEET 1 OF 3**	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT IX-2

ERCOT - ELECTRIC UTILITIES (Cont'd)

Other Members of ERCOT: (Cont'd)

Cooperatives: (Cont'd)

Farmers
Fayettee
Grayson-Collin
Guadelupe Valley
Hamilton County
Hill County
Hunt-Collin
J-A-C
Jackson
Jasper-Newton
Johnson County
Kaufman County
Kimble
Lamar County
Limestone County
Lone Wolf
Magic Valley
McCulloch
McLennan County
Mid-South
Midwest
Navarro County
New Era
Pedernales
Robertson
Sam Houston
San Bernard
San Patricio
Southwest Texas
Stamford
Taylor
Tri-County
Victoria County
Wharton County
Wise

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY ERCOT LIST OF UTILITIES SHEET 2 OF 3	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT IX-2

ERCOT - ELECTRIC UTILITIES (Cont'd)

Other Members of ERCOT (Cont'd)

Municipalities:

Boerne
Brady
Brenham
Coleman
Crosbyton
Cuero
Giddings
Goldthwaite
Gonzales
Hearne
Hemphill
Hondo
La Grange
Livingston
Lockhart
Luling
New Braunfels
Robstown
Schulenberg
Seguin
Weimar

Investor Owned:

Community Public Service Co.
Southwestern Electric Service Co.

Source: NERC, "1977 Annual Report," March 1978.

ERCOT

ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate-% 1 yr	Annual Energy: Average Annual Growth Rate-% 5 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-% 1 yr	Peak Demand: Average Annual Growth Rate-% 5 yr	Load Factor-%
1965 1/	49.5	-	-	10.3	-	-	54.9
1970 1/	79.2	-	9.9	16.5	-	9.9	54.8
1973	105.4	-	-	20.7	-	-	58.1
1974	108.6	3.0	-	23.0	11.6	-	53.9
1975	115.9	6.7	-	23.1	0.4	-	57.3
1976	122.2	5.4	-	25.2	8.8	-	55.2 2/
1977	136.4	11.6	-	26.8	6.5	-	58.1

1/ From FPC Power Supply Areas 37 and 38.

2/ Load Factor was computed using 8784 hours to reflect leap year.

SOURCE: 1. Federal Power Commission "The 1970 National Power Study", Part III, Washington, D.C., 1970.

2. ERCOT Report to the U.S. Department of Energy on coordinated bulk power supply programs, FERC (FPC) Order 383-4, Docket R-362, April 1, 1978.

3. Data from the Electric Reliability Council of Texas.

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ERCOT** **ELECTRIC POWER DEMAND**	
CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT IX-3

ERCOT
SYSTEM LOAD VARIATIONS 1/
1977

Representative Utilities	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor-%	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor-%	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor-%	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWH	Annual: Load Factor %
City of Austin Electric Utilities	43.3	76.1	93.5	72.0	52.8	74.1	774	Aug. 24	3,105	45.8
Central Power & Light Co.	64.1	83.6	97.7	80.4	67.8	82.0	2,320	Aug. 3	12,106	59.6
Dallas Power & Light Co.	51.5	73.3	97.7	75.1	58.5	74.8	2,495	Aug. 24	11,138	51.0
Houston Lighting & Power Co.	64.1	84.1	99.7	79.3	67.7	86.2	8,645	Jul. 25	48,524	64.1
Lower Colorado River Authority	49.2	77.4	93.2	74.1	74.9	64.5	844	Aug. 23	3,741	50.6
City of San Antonio Public Service	45.7	77.2	93.2	73.5	48.9	75.9	1,641	Aug. 23	6,674	46.4
South Texas & Medina Cooperatives										
Texas Electric Service Co.	57.6	83.3	96.8	79.6	70.2	80.3	3,594	Jul. 26	18,649	75.0
Texas Power & Light Company	55.2	80.8	99.2	75.5	70.9	76.4	4,754	Aug. 17	23,440	56.3
Texas Municipal Power Pool										
West Texas Utilities Co.	59.6	86.0	95.2	79.2	72.6	82.0	784.5	Sept.27	4,181	60.8

1/ Computations based on information provided in schedules 14 and 15 of the 1977 FERC Form 12

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

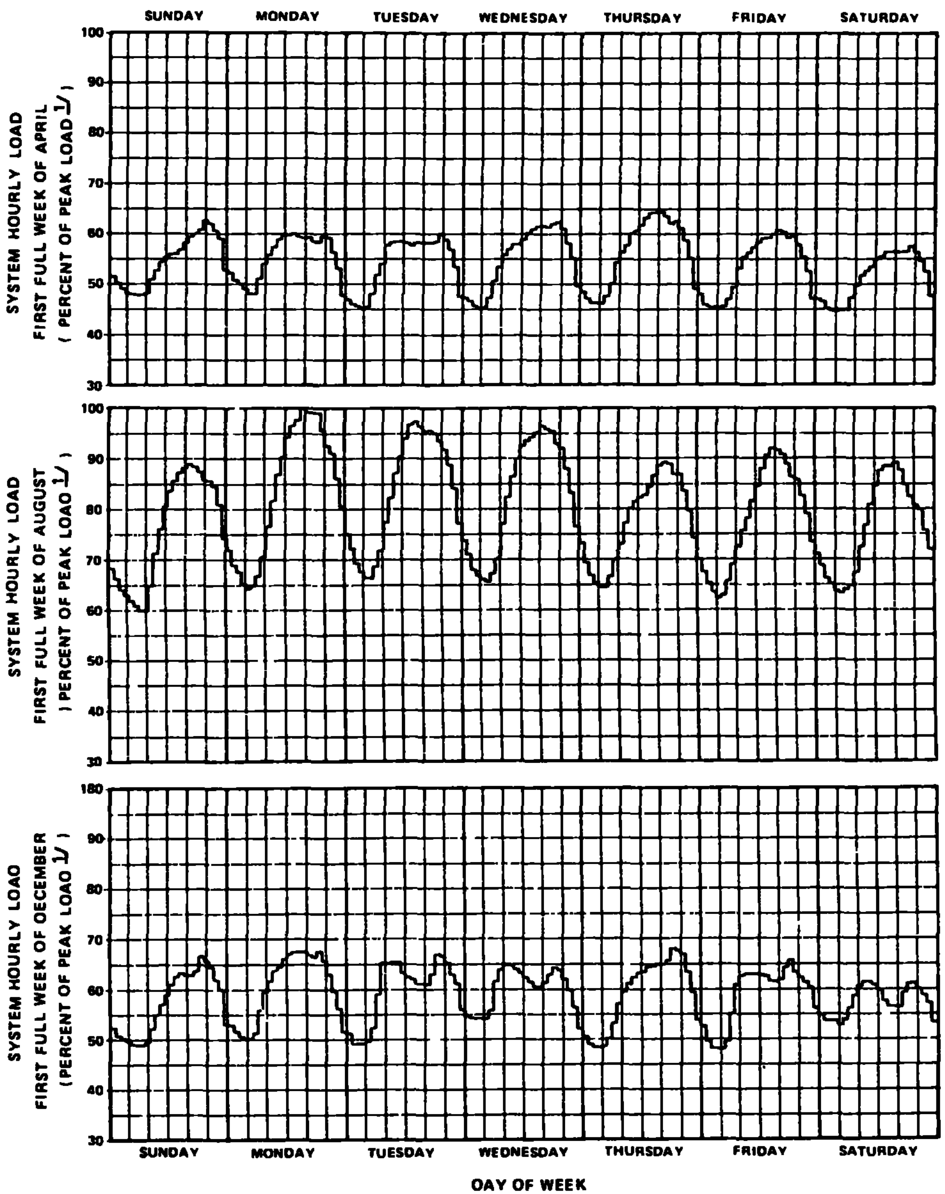
DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

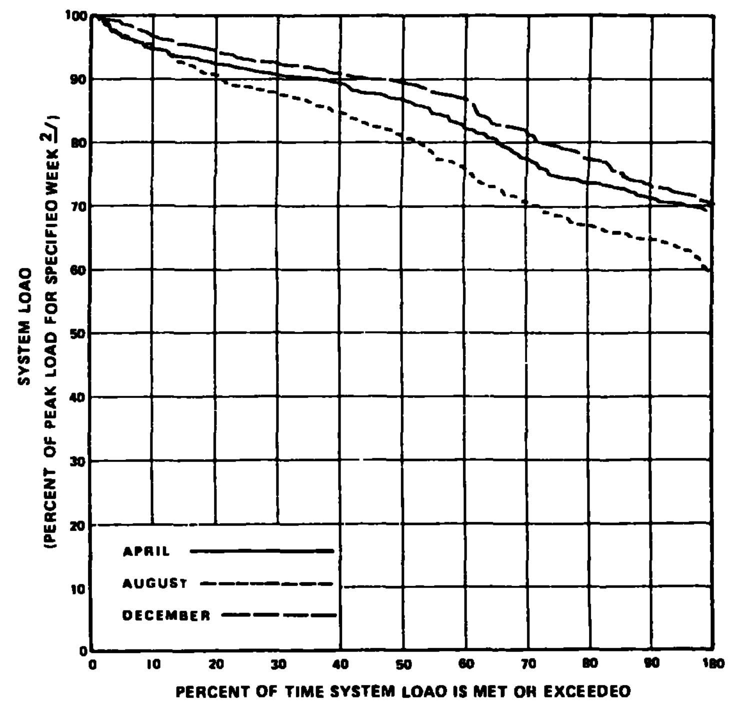
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

ERCOT
SYSTEM LOAD VARIATIONS, 1977

MARCH, 1979

EXHIBIT IX-4





NOTES.

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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION ERCOT
SUB-REGION ERCOT
UTILITY HOLP

MARCH, 1979

EXHIBIT IX-5

ERCOT
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
City of Austin Electric Utilities	MW	-	1,400	-	-	-	-	-	-	-	-	-	-	1,400
	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100
Central Power & Light Company	MW	-	3,100	-	-	-	-	-	-	-	50	-	-	3,150
	%	-	98.4	-	-	-	-	-	-	-	1.6	-	-	100.0
Dallas Power & Light Company	MW	-	2,955	763	-	-	-	-	-	-	-	-	-	3,718
	%	-	79.5	20.5	-	-	-	-	-	-	-	-	-	100.0
Houston Lighting & Power Company	MW	-	8,727	660	-	542	-	-	901	-	-	-	-	10,830
	%	-	80.6	6.1	-	5.0	-	-	8.3	-	-	-	-	100.0
Lower Colorado River Authority	MW	-	1,050	-	-	-	230	-	-	-	-	-	-	1,280
	%	-	82.0	-	-	-	18.0	-	-	-	-	-	-	100.0
City of San Antonio Public Service	MW	-	2,290	418	-	-	-	-	-	-	-	-	-	2,708
	%	-	84.5	15.5	-	-	-	-	-	-	-	-	-	100.0
South Texas and Medina Electric Cooperatives, Pool	MW	-	101	-	-	-	-	-	-	-	22	-	-	123
	%	-	82.1	-	-	-	-	-	-	-	17.9	-	-	100.0
Texas Electric Service Company	MW	-	4,320	878	-	-	-	-	-	-	-	3	-	5,201
	%	-	83.0	16.9	-	-	-	-	-	-	-	0.1	-	100.1
Texas Power & Light Company	MW	-	4,780	1,408	-	-	-	-	-	-	-	20	-	6,208
	%	-	77.0	22.7	-	-	-	-	-	-	-	0.3	-	100.0
Texas Municipal Power Pool		-	-	-	-	-	-	-	-	-	-	-	-	-
City of Bryan	MW	-	119	-	-	-	-	-	21	-	-	-	-	140
	%	-	85.0	-	-	-	-	-	15.0	-	-	-	-	100.0
Brazos Elec. Power	MW	-	525	-	-	-	-	-	-	-	-	-	-	525
Cooperative, Inc.	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
City of Denton	MW	-	167	-	-	-	-	-	-	-	-	-	-	167
	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
City of Garland	MW	-	425	-	-	-	-	-	-	-	-	-	-	425
	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
City of Greenville	MW	-	85	-	-	-	-	-	-	-	15	-	-	100
	%	-	85.0	-	-	-	-	-	-	-	15.0	-	-	100.0
West Texas Utilities Company	MW	-	920	-	-	-	-	-	131	-	-	3	-	1,054
	%	-	87.3	-	-	-	-	-	12.4	-	-	0.3	-	100.0
ERCOT Total	MW		30,964	4,127	-	542	230	-	1,053	50	37	26	-	37,029
	%		83.6	11.1	-	1.5	0.6	-	2.8	0.2	0.1	0.1	-	100.0

SOURCE: Based on winter generating capability reported to the Department of Energy, FERC (FPC) Order 383-4, Docket R-362, April 1978.

HARZA ENGINEERING COMPANY

DEPARTMENT OF THE ARMY

ERCOT
EXISTING GENERATING CAPABILITY

DATE MARCH, 1979

EXHIBIT IX-6

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND WSCC REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

WSCC

CONTRACT NO DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT X-1

WSCC - REPORTING UTILITIES

Letter Code	Sub-Region
NWPP	NORTHWEST POWER POOL AREA
	Members of WSCC:
BPA	Bonneville Power Administration
BCHA	British Columbia Hydro & Power Authority 1/
USCE	Corps of Engineers (North Pacific Division)
EWEB	Eugene Water and Electric Board
IPC	Idaho Power Company
MPC	Montana Power Company
PPL	Pacific Power & Light Company
PGE	Portland General Electric Company
CHPD	PUD No. 1 of Chelan County
COPD	PUD No. 1 of Cowlitz County
DOPD	PUD NO. 1 of Douglas County
GCPD	PUD of Grant County
PSPL	Puget Sound Power & Light County
SCL	Seattle Department of Lighting (Seattle City Light)
TCL	Tacoma Department of Public Utilities (Tacoma City Light)
USPN	U.S.B.R. (Pacific Northwest)
USUC	U.S.B.R. (Upper Colorado)
UPLC	Utah Power & Light Company
WWPC	Washington Water Power Company
WKPL	West Kootenay Power & Light Company 1/
	Affiliate Members of WSCC:
BTFL	Bountiful City Light and Power (City of Bountiful)
	Non-Members of WSCC:
BF	Bonners Ferry
CC	City of Centralia
CPU	California-Pacific Utilities
POPD	Pend Oreille County PUD

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **WSCC** **LIST OF UTILITIES** **PAGE 1 OF 4**	
CONTRACT NO DACW72-78-C-0013 DATE MARCH, 1979	EXHIBIT X-2

WSCC - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
RMPA	ROCKY MOUNTAIN POWER AREA
	Members of WSCC:
BHPL	Black Hills Power & Light Company
CCS	City of Colorado Springs
CUEA	Colorado-Ute Electric Association
PRPA	Platte River Power Authority
PSC	Public Service Company of Colorado
SCPC	So. Colorado Power Division, Central Telephone & Utilities Corporation
TSGT	Tri-State G&T Association, Inc.
USLM	U.S.B.R. (Lower Missouri)
USUC	U.S.B.R. (Upper Colorado)
	Affiliate Members of WSCC:
COL	Lamar Utilities Board (City of Lamar)
ARZ-NM	ARIZONA-NEW MEXICO POWER AREA
	Members of WSCC:
AEPC	Arizona Electric Power Cooperative, Inc.
APS	Arizona Public Service Company
EPE	El Paso Electric Company
PEGT	Plains Electric Generation and Transmission Cooperative, Inc.
PNM	Public Service Company of New Mexico
SRP	Salt River Project
TGE	Tucson Gas & Electric Company
USLC	U.S.B.R. (Lower Colorado)
USSW	U.S.B.R. (Southwest)
	Non-Members of WSCC:
CUC	Citizens Utility Company
IID	Imperial Irrigation District
LAS	Los alamos Systems
SCIP	San Carlos Irrigation Project

WSCC - REPORTING UTILITIES (Cont'd)

Letter Code	Sub-Region
SO. CAL-NEV	SOUTHERN CALIFORNIA - NEVADA POWER AREA
	Members of WSCC:
CDWR	Department of Water Resources/California 2/
GLEN	Glendale Public Service Department
LDWP	Los Angeles Department of Water and Power
MWD	Metropolitan Water District/Southern California
NEVP	Nevada Power Company
PASA	City of Pasadena
SDGE	San Diego Gas & Electric Company
SCE	Southern California Edison Company
	Non-Members of WSCC:
BURB	City of Burbank
SNEW	State of Nevada
NO.CAL-NEV	NORTHERN CALIFORNIA-NEVADA POWER AREA
	Members of WSCC:
CDWR	Department of Water Resources/California 2/
PG&E	Pacific Gas & Electric Company
SMUD	Sacramento Municipal Utility District
SPP	Sierra Pacific Power Company
USMP	U.S.B.R. (Mid-Pacific)
	Non-Members of WSCC:
CCFS	City and County of San Franciso
TMID	Turlock and Modesto Irrigation District

Utility Systems Whose Data Is Reported By Other WSCC Systems Previously Listed

Members of WSCC:

APA	Arizona Power Authority
USFC	U.S.B.R. (Denver Federal Center)
USUM	U.S.B.R. (Upper Missouri)
WAPA	Western Area Power Administration
WAFC	(Denver Federal Center)
WALC	(Boulder City, Nevada)
WALM	(Denver, Colorado)
WAMP	(Sacramento, California)
WAUC	(Salt Lake City, Utah)
WAUM	(Billings, Montana)

HARZA ENGINEERING COMPANY
CONSULTING ENGINEERS
CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

WSCC

LIST OF UTILITIES

CONTRACT NO DACW72 - 78 - C - 0013

DATE MARCH, 1979

EXHIBIT X–2

WSCC REPORTING UTILITIES(cont'd)

Utility Systems Whose Data Is Reported By
Other WSCC Systems Previously Listed (cont'd)

Affiliate Members of WSCC:

City of Anaheim
Electric District No. 2, Coolidge, Arizona
Garkane Power Association, Inc.
City of Lodi
Navajo Tribal Utility Authority
City of Palo Alto
PUD of Clark County, Vancouver, Washington
City of Redding
City of Riverside
City of St. George
City of Santa Clara

1/ These utility systems are located in Canada and have been excluded from calculations.

2/ The Department of Water Resources/California reports in both the Southern California-Nevada Power Area and the Northern California-Nevada Power Area.

NOTE:

There are additional systems which have not been included in the above list. However, data for these systems are report by the respective systems listed above for the various regions. The number of systems not listed in each Region are as follows:

Region	No. of Systems
NWPP	155
RMPA	110
ARZ-NM	32
So.Cal-Nev	12
No.Cal-Nev	23

SOURCE: "Reliability and Adequacy of Electric Service", WSCC response to U.S. Department of Energy, Order 383-5, Docket R-362, April 1, 1978.

WSCC

ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWH	Annual Energy: Average Annual Growth Rate-% 1 yr	Peak Demand: Peak GW	Peak Demand: Average Annual Growth Rate-% 1 yr	Annual Load Factor-%
WSCC					
1975	357.9	-	65.2	-	62.7
1976	385.2	7.6	69.8	7.1	62.8
1977	385.9	0.2	64.9	(7.0)	67.8
NORTHWEST POWER POOL AREA					
1975	141.8	-	23.6	-	68.6
1976	155.3	9.5	25.5	8.1	69.3
1977	153.0	(1.5)	26.6	4.3	65.6
ROCKY MOUNTAIN POWER AREA					
1975	21.6	-	3.8	-	64.9
1976	23.3	7.9	4.1	7.9	64.7
1977	24.4	4.7	4.2	2.4	66.2
ARIZONA-NEW MEXICO POWER AREA					
1975	30.1	-	6.6	-	52.1
1976	33.9	12.6	7.0	6.1	55.1
1977	35.8	5.6	7.3	4.3	56.2
SOUTHERN CALIFORNIA-NEVADA POWER AREA					
1975	91.0	-	17.2	-	60.4
1976	95.7	5.2	18.6	8.1	58.6
1977	96.7	1.0	18.8	1.1	58.6
NORTHERN CALIFORNIA-NEVADA POWER AREA					
1975	73.4	-	14.0	-	59.8
1976	77.0	4.9	14.6	4.3	60.0
1977	76.0	(1.3)	14.2	(2.7)	61.3

WSCC
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

Representative Utilities	RESIDENTIAL 1972	1973	1974	1975	1976	1977	COMMERCIAL 1972	1973	1974	1975	1976	1977	INDUSTRIAL 1972	1973	1974	1975	1976	1977	TOTAL 1972	1973	1974	1975	1976	1977
NORTHWEST POWER POOL AREA																								
Pacific Power & Light Company	NA	NA	2.2	7.2	1.9	2.3	NA	NA	0.9	9.1	5.3	7.6	NA	NA	1.1	(1.2)	8.5	5.7	NA	NA	1.5	4.6	9.9	4.7
Portland General Elec. Company	4.8	1.3	0.3	6.0	0.8	1.9	12.3	5.6	(0.6)	20.4	(3.9)	4 3	12.4	4.8	2.4	(19.8)	27.4	1.4	8.8	3.4	0.7	1 4	6.1	8.6
PUD No. 1 of Douglas County 4/	-	-	4.3 1/	12.9	NA	NA							-	-	-	-	-	-	-	-	4.5 1/	37.3	NA	NA
Puget Sound Power & Light Company	9.9 2/	1 2	2.6	9 8	8.0	3.3	13.1 2/	9.6	(1.7)	18.9	6.8	4 0	8.0 2/	9.4	0.4	(0.4)	(1.5)	1.7	10.2 2/	4.9	1.1	7.8	5.7	9.1
Utah Power & Light Company	NA	12.3	11.4	2.6	4 6	3.3	NA	11.0	4.7	5.6	8 9	5.5	NA	14.5	(1.3)	13.1	(3.9)	14.7	NA	13.0	3.9	8.0	1 5	8 9
ROCKY MOUNTAIN POWER AREA																								
City of Colorado Springs 4/	13.7	11.0	1.4	4.3	3.2	2.7							-	-	-	-	-	-	13.3	7.6	2.1	9.1	12.4	2.0
Public Service Company of Colorado 5/	NA	8.5	7.8	9.8	1.3	3.9	NA	11.2	2.3	4.5	6.5	3.8	NA	4.9	27 7	1.8	0.0	14.3	NA	9.8	9.8	7.8	4.5	9.6
ARIZONA-NEW MEXICO POWER AREA																								
El Paso Electric Company 6/	8.0	8 8	1.3	2.2	4.3	7.1	12.7	12.9	1 9	4.5	6.2	0.6	-	-	-	-	-	-	10.9	11.3	1 7	3.7	5.5	2.9
Public Service Company of New Mexico	9.0	11.2	5.4	5.7	4.7	4.4	11.2	12.7	1.7	4.4	8.4	3.4	5 9	(5.7)	(10.8)	(3.5)	14.2	13.4	9.0	7.1	(10 2)	3.1	8 4	14.8
Salt River Project	15.4 2/	-	-	-	6.7 3/	8.1	15.4 2/	-	-	-	8.1 3/	3 7	-	-	-	-	-	-	15.4 2/	-	-	-	7.5 3/	5.7
Tuscon Gas & Electric Company	NA	NA	NA	-	0.6	NA	NA	NA	NA	-	4.9	NA	NA	NA	NA	-	7 4 8/	NA	NA	NA	NA	-	5.0	NA
SOUTHERN CALIFORNIA-NEVADA POWER AREA																								
Los Angeles Department of Water & Power	5.7	1.7	(8.5)	NA	NA	NA	6.4	5.4	(12.5)	NA	NA	NA	4.4	1.9	0.0	NA	NA	NA	5 8	3.7	(9.0)	NA	NA	NA
San Diego Gas & Electric Company 7/	9.5	8.2	1.1	6.5	6.2	4.3	9.1	7.0	(3.7)	6.5	2.0	1.7	-	-	-	-	-	-	9.3	7.4	(1.9)	6.5	3.7	2.7
Southern California Edison Company 9/	-	0.0	(3.4)	0.0	3.5	0.0	-	8.1	(7 5)	8.1	3.7	3.6	-	2.8	(0.6)	(1.0)	3.1	3.0	-	2 2	(4 4)	1.1	3.4	2.2
NORTHERN CALIFORNIA-NEVADA POWER AREA																								
Pacific Gas & Electric Company 10/	7 0	6.5	(1.0)	5.2	3.7	NA	-	-	-	-	-	-	11.5	9.5	(9.4)	0.8	9.5	NA	8.3	7.4	(0.7)	3.7	5.1	NA
Sacramento Municipal Utility District 11/	7.5	8.1	1.6	6.8	3.4	5.7	-	-	-	-	-	-	8.2	5.9	(4.6)	6.7	5.4	1.6	7.9	6.9	(1.8)	6.8	4.4	3.5

Source 1977 Annual Reports of respective utilities.

1/ Average Annual Growth Rate over a three-year period.
2/ Average Annual Growth Rate over a five-year period.
3/ Average Annual Growth Rate over a four-year period.
4/ Commercial and Industrial categories not available.
5/ PSC data was estimated from graphs Industrial cateogry includes others
6/ Commercial and Industrial small and large are combined and shown under the Commercial category.
7/ Commercial and Industrial are combined and shown under the Commercial category.
8/ Industrial is the sum of large users and mining.
9/ Data estimated from graphs.

WSCC
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION
MARCH, 1979
EXHIBIT X-4

WSCC
SYSTEM LOAD VARIATIONS 1/
1977

Representative Utilities	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
NORTHWEST POWER POOL AREA										
Idaho Power Company	60.6	83.8	86.5	83.2	72.7	77.6	1,761	June 28	9,438	61.2
Montana Power Company	75.3	86.3	76.4	83.4	100.0	82.4	1,077	Dec 08	6,244	66.2
Pacific Power & Light Co.	72.1	76.9	73.2	79.3	93.0	76.4	3,017	Jan 06	15,746	59.6
Portland General Electric Co.	75.0	73.2	67.3	79.6	86.7	77.1	2,551	Nov 21	12,939	59.7
PUD No. 1 of Chelan County	73.0	93.4	73.0	91.4	100.0	80.2	389 1/	Dec 04	2,388	80.1
PUD of Grant County	72.2	81.2	94.8	82.4	82.7	79.8	248	June 30	1,516	69.8
Utah Power & Light Co.	72.8	79.4	93.1	78.1	80.5	83.1	1,950	Jul 18	10,723	62.8
Washington Water	64.4	80.9	61.6	77.2	93.7	79.0	1,307	Jan	NA	56.5
Bonneville Power Administration	74.7	86.5	68.0	90.8	89.5	84.5	8,740	Jan 7	52,409	68.5
ROCKY MOUNTAIN POWER AREA										
Black Hills Power & Light Co.	77.8	72.4	77.8	74.7	98.2	78.0	171	Dec 08	901	60.0
City of Colorado Springs	82.8	74.0	88.0	73.1	98.5	69.6	274	Jul 18	1,546	64.4
Colorado-Ute Electric Assoc.	78.3	79.6	79.2	81.2	83.1	80.3	337	Dec 20	1,851	62.7
Public Service Co. of Colorado	77.2	81.5	90.2	76.8	93.2	75.9	2,432	Jul 19	13,707	64.3
ARIZONA-NEW MEXICO POWER AREA										
Arizona Public Service Co.	57.4	80.6	96.3	79.1	53.9	83.6	2,270	Aug 04	10,773	54.2
El Paso Electric Company	68.8	78.2	97.0	73.1	72.9	77.3	657	Aug 24	3,472	60.3
Public Service Co. of N. Mexico	73.1	78.7	97.8	68.8	81.6	76.1	625	Jul 29	3,462	62.5
Salt River Project	60.9	79.4	95.4	76.1	58.9	81.3	1,783	Sept 07	8,122	52.0
Tucson Gas & Electric Co.	68.9	82.3	87.0	75.4	64.0	79.2	811	June 29	4,162	70.3
SOUTHERN CALIFORNIA-NEVADA POWER AREA										
Glendale Public Service Dept.	63.8	70.6	81.4	65.9	69.8	68.4	177	Jul 27	746	48.1
Los Angeles Dept. Water & Power	70.5	74.4	87.6	70.0	79.7	72.6	3,765	Jul 27	18,498	60.2
City of Pasadena	69.7	68.3	86.9	66.3	72.6	71.0	175	Sept 08	795	51.9
San Diego Gas & Electric Co.	78.8	75.7	85.4	74.4	90.0	69.4	1,746	Sept 07	9,327	61.0
Southern California Edison Co.	73.2	77.1	90.6	73.0	77.2	74.8	11,249	Sept 07	58,705	61.6
NORTHERN CALIFORNIA-NEVADA POWER AREA										
Pacific Gas & Electric Co.	73.4	79.3	88.4	76.6	78.3	77.3	12,192	Aug 01	65,511	61.3
Sacramento Municipal Utility District	51.0	72.4	83.8	55.8	58.9	74.9	1,354	Sept 06	5,068	42.7
Sierra Pacific Power Co.	77.0	81.1	88.2	80.2	86.9	76.5	536	Dec 20	3,245	69.1

1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12.

2/ Peak demand of 389 was taken from Schedule 15 (Dec. 4) which was greater than annual peak demand given on Schedule 14 (382, Dec. 27).

HARZA ENGINEERING COMPANY

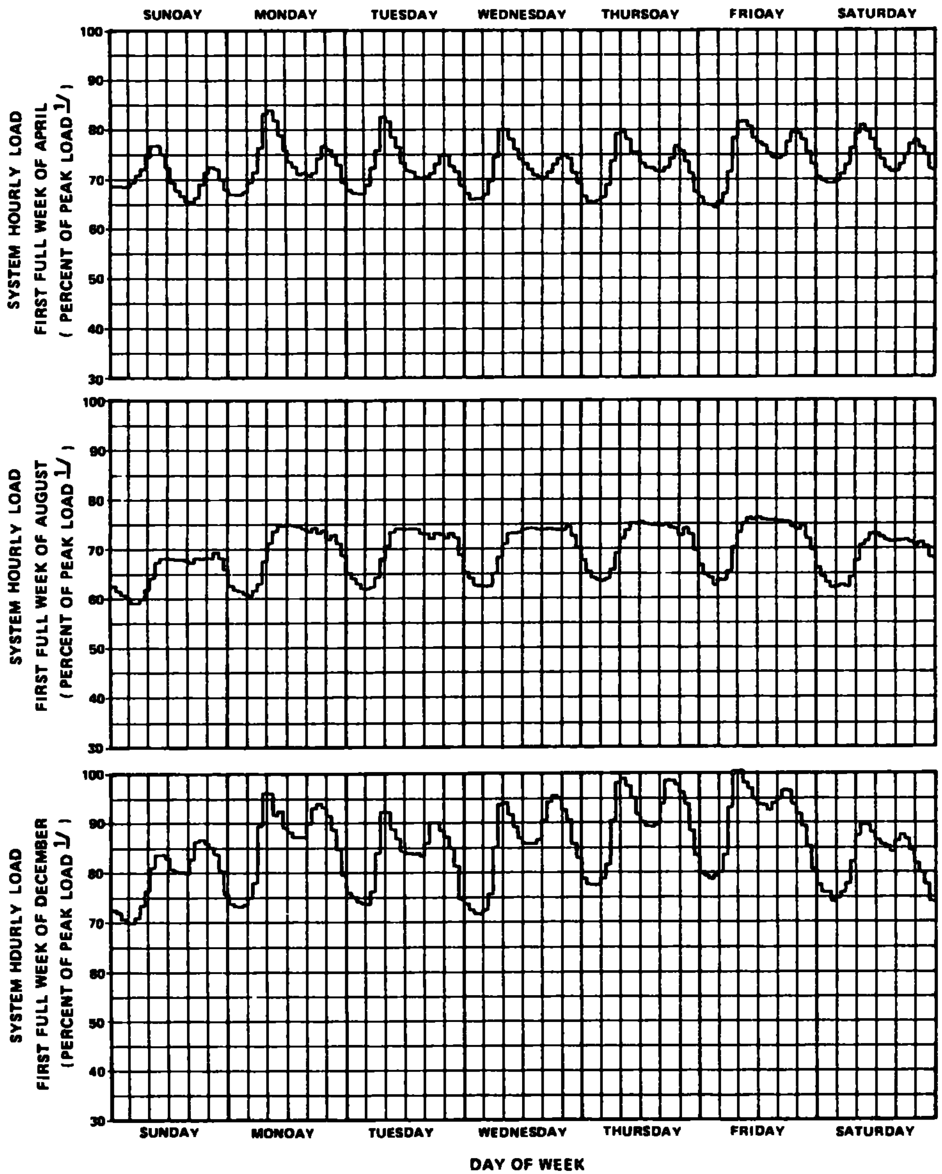
DEPARTMENT OF THE ARMY

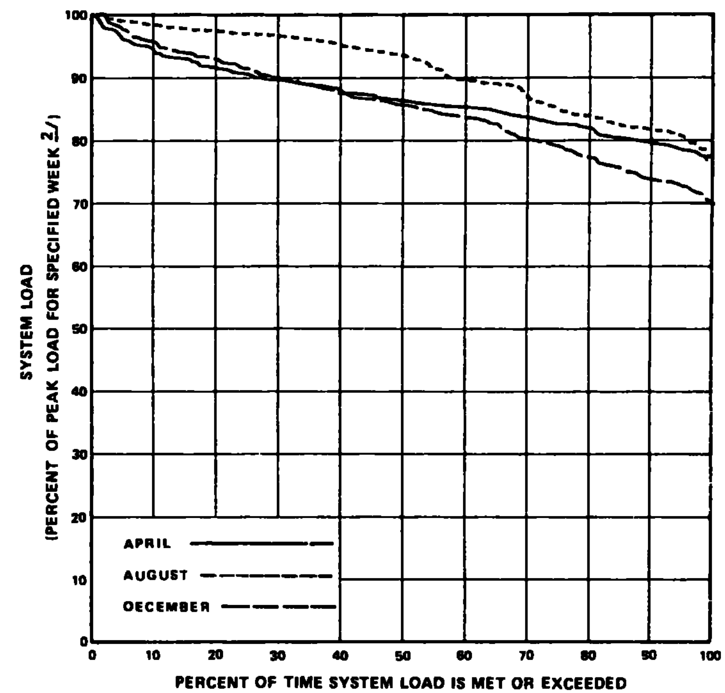
WSCC

SYSTEM LOAD VARIATIONS, 1977

MARCH 1979

EXHIBIT X-5





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE:

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION WSCC

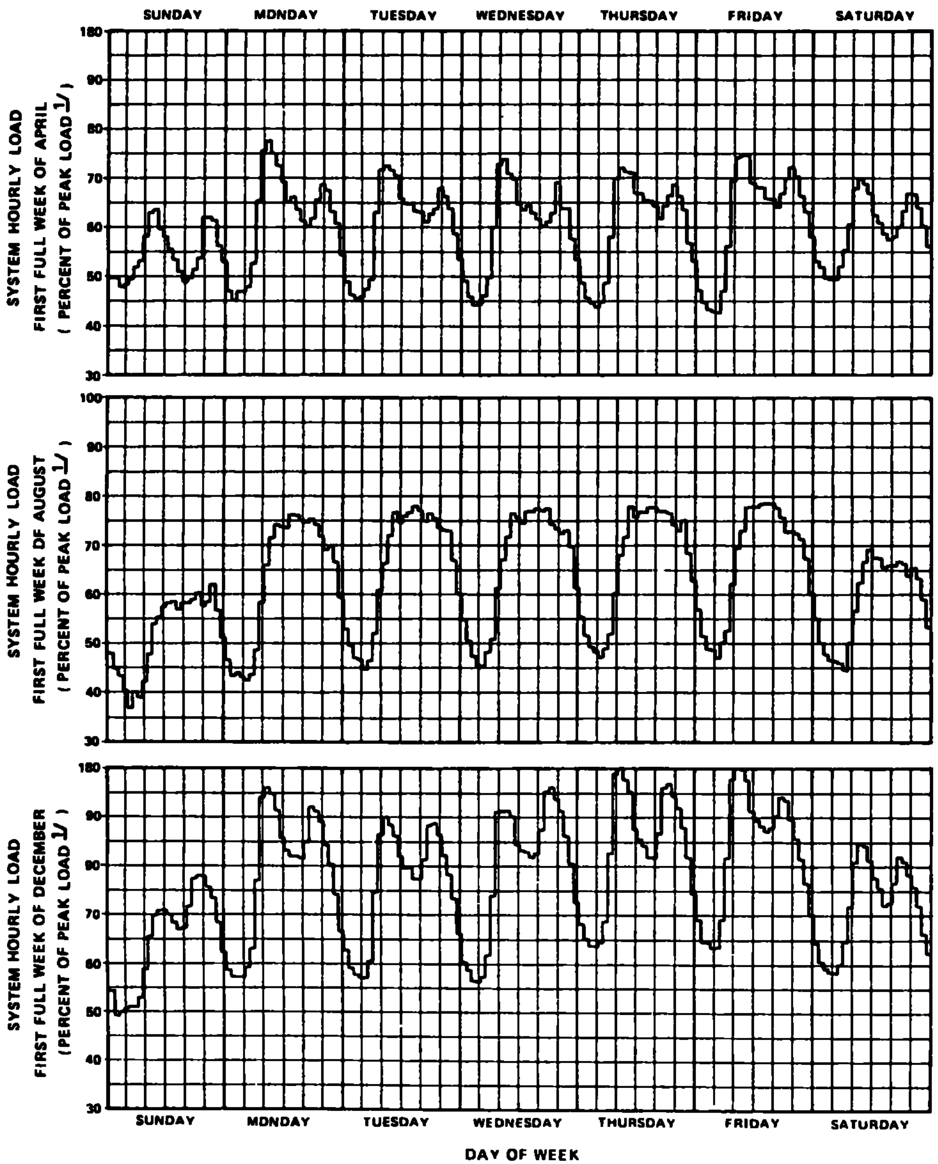
SUB-REGION NWPP

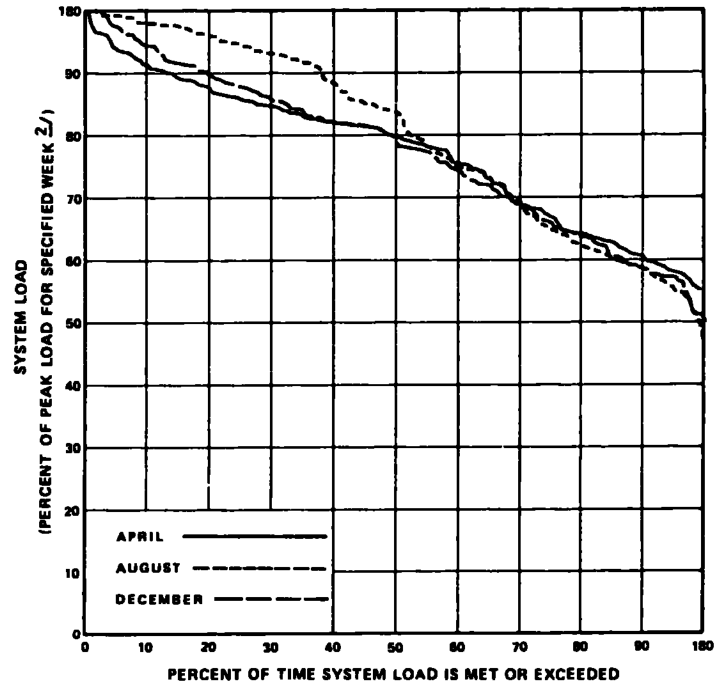
UTILITY BPA

SHEET 1 OF 6

DATE MARCH, 1979

EXHIBIT X-6





NOTES

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SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

DEPARTMENT OF THE ARMY

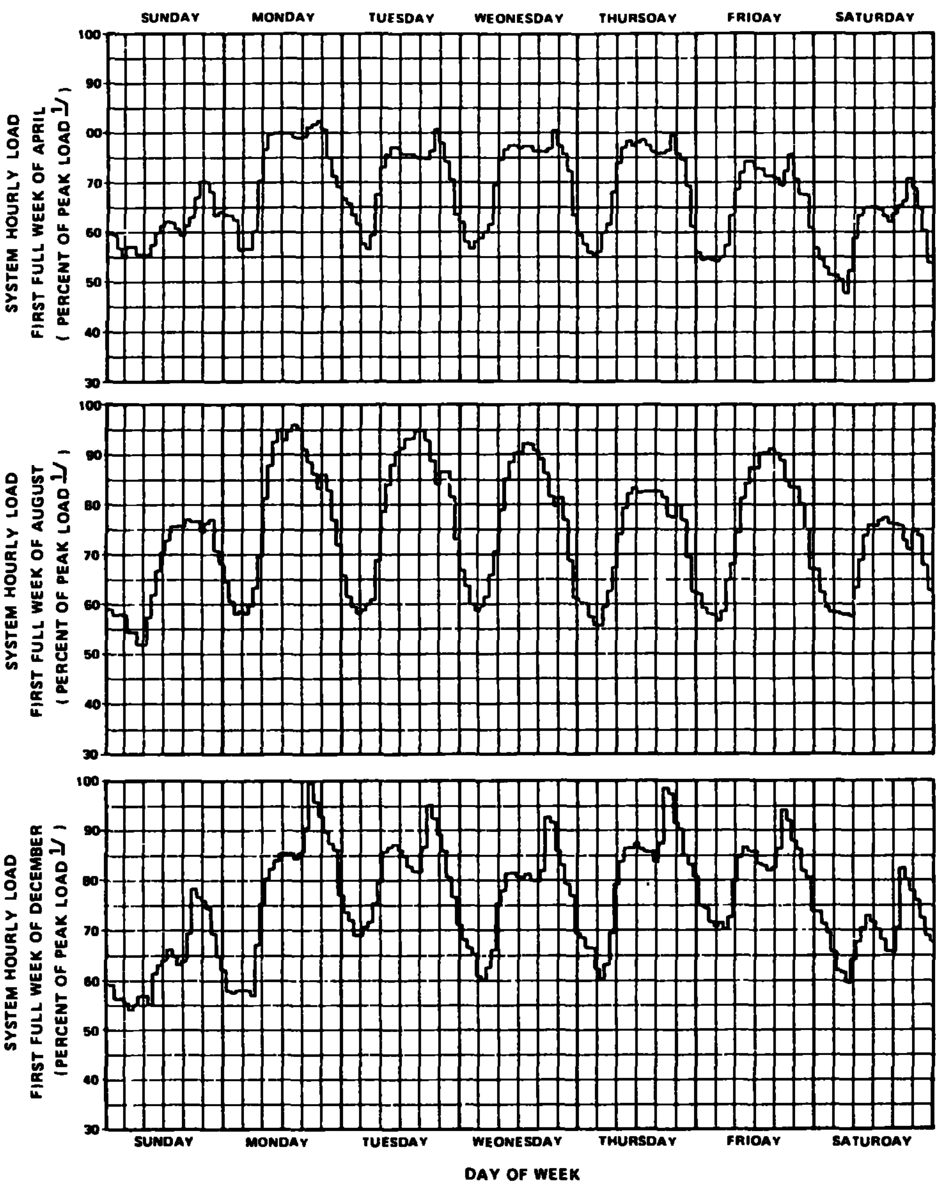
LOAD CURVES

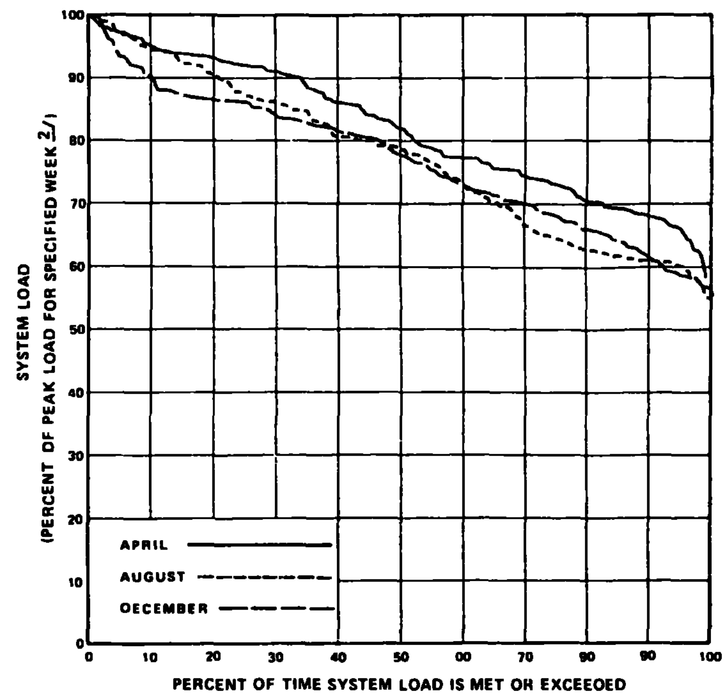
REGION WSCC
SUB-REGION NWPP
UTILITY PPL

SHEET 2 OF 6

MARCH 1979

EXHIBIT X-6





NOTES

1 PEAK LOAO IS EQUAL TO THE LARGEST SYSTEM LOAO IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND OECEMBER

2 PEAK LOAO IS THE PEAK SYSTEM LOAO FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR OECEMBER CURVES

SOURCE

DATA OBTAINEO FROM FERC FORM NO 12 (SCHEOULES 14 ANO 15) FOR 1977

DEPARTMENT OF THE ARMY

CORPS OF ENGINEERS

LOAD CURVES

REGION WSCC

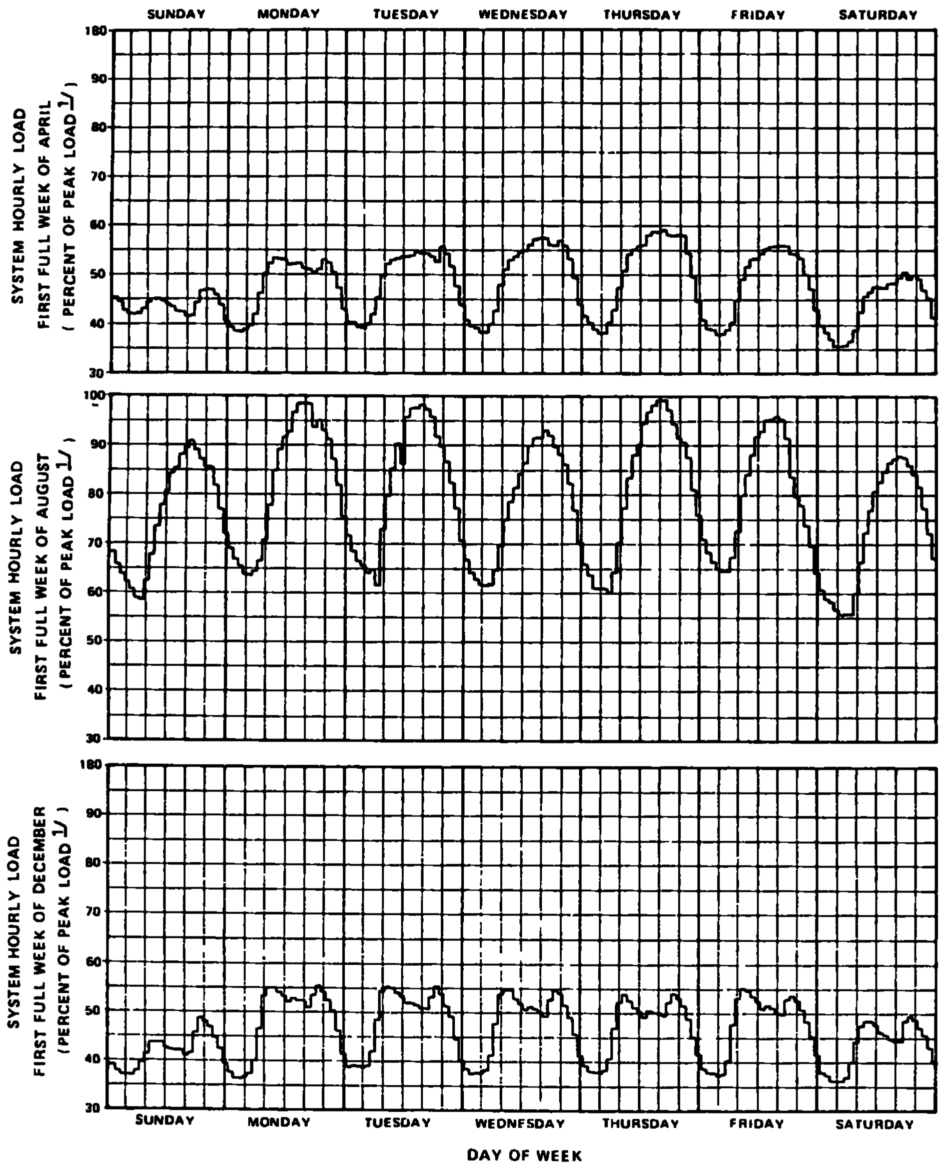
SUB–REGION RMPA

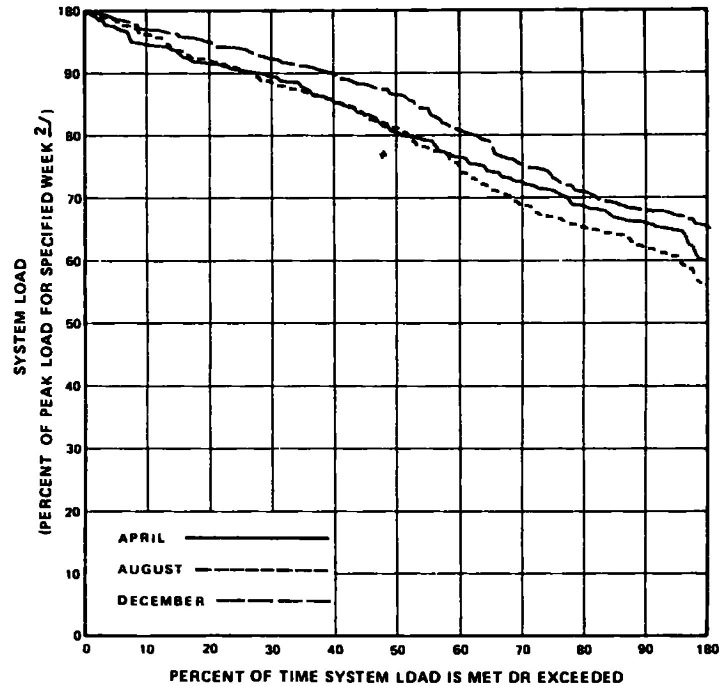
UTILITY PSC

SHEET 3 OF 6

MARCH 1979

EXHIBIT X–6





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL AUGUST AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

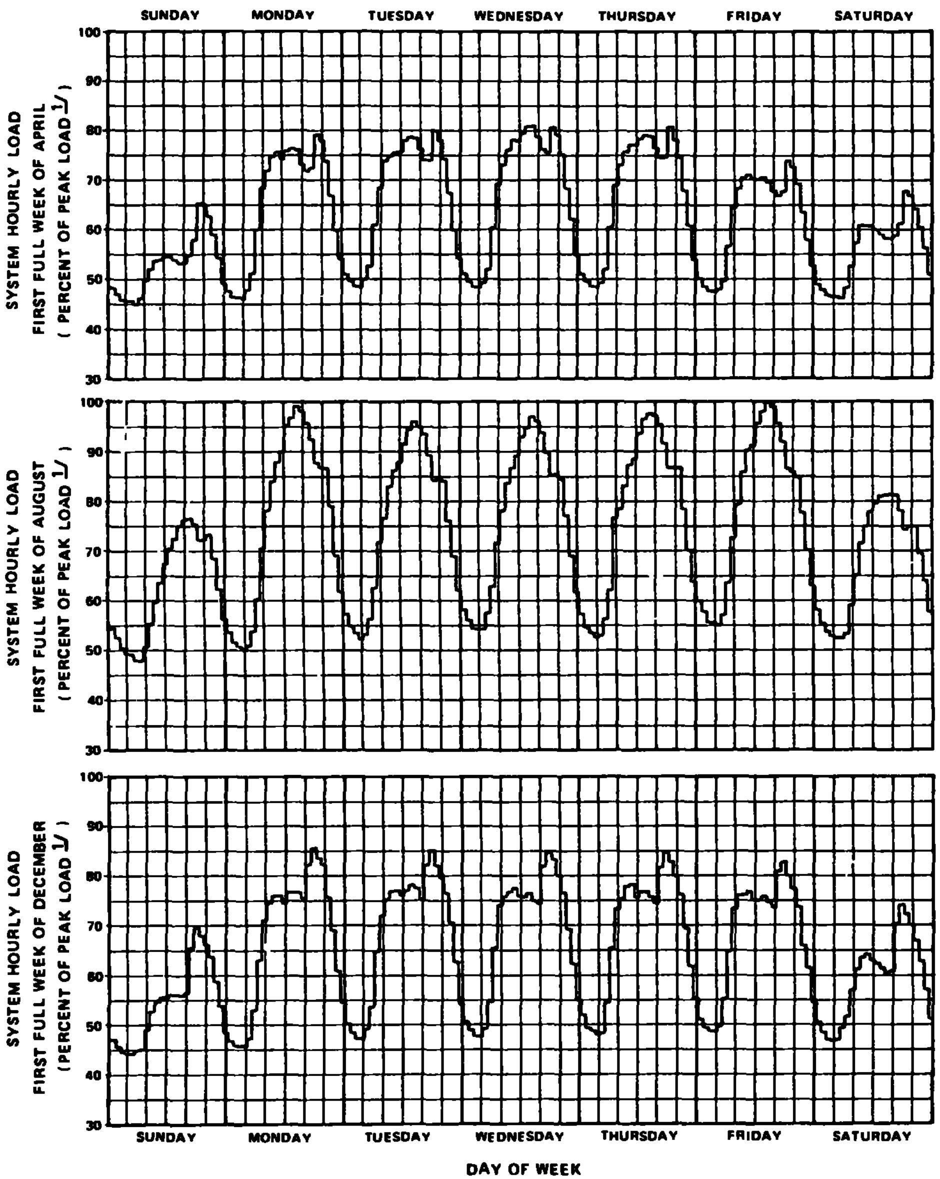
DEPARTMENT OF THE ARMY

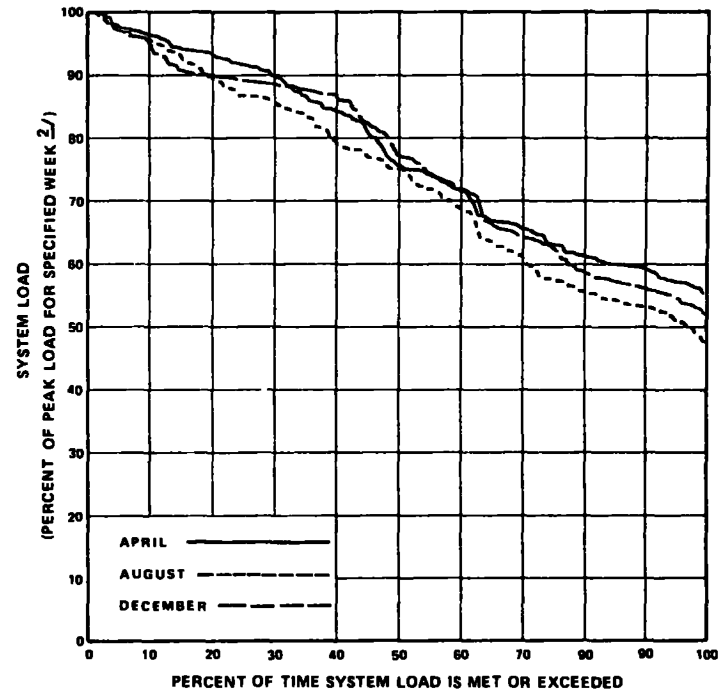
LOAD CURVES

REGION WSCC
SUB REGION ARZ NM
UTILITY APS

SHEET 4 OF 6

EXHIBIT X-6





NOTES

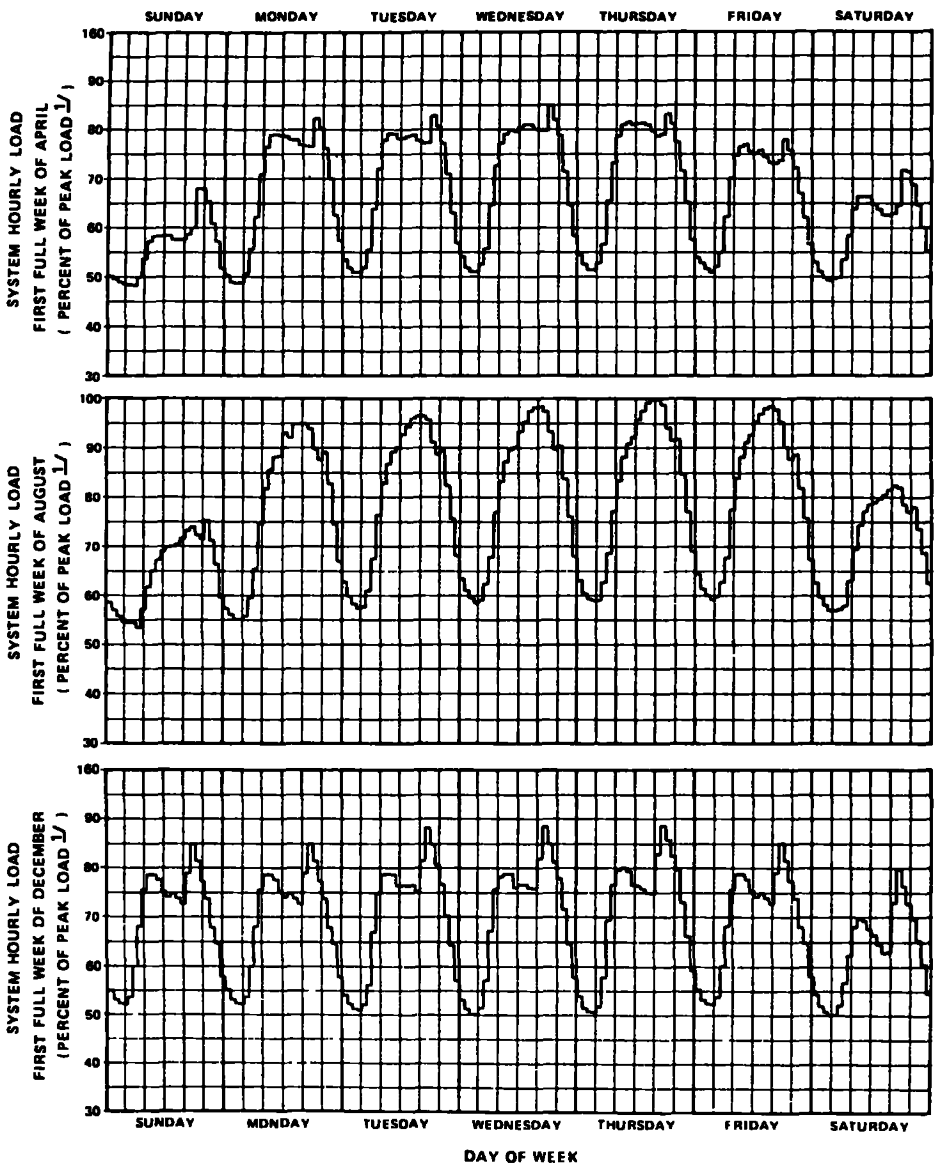
1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

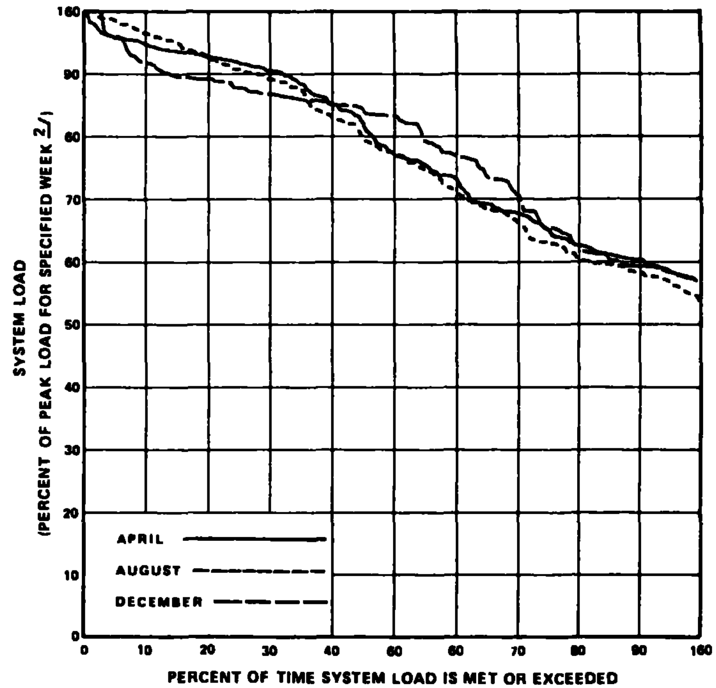
2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES	
REGION	WSCC
SUB-REGION	SO CAL-NEV
UTILITY	SCE
SHEET 5 OF 6	
DATE MARCH 1979	EXHIBIT X-6





NOTES.

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

DEPARTMENT OF THE ARMY

LOAD CURVES

REGION WSCC

SUB-REGION ND CAL-NEV

UTILITY· PG & E

SHEET 6 OF 6

MARCH, 1979

EXHIBIT X-6

WSCC
NORTHWEST POWER POOL AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Bonners Ferry	MW	-	-	-	-	-	2	-	-	-	-	2	-	4
	%	-	-	-	-	-	50.0	-	-	-	-	50.0	-	100.0
Bonneville Power	MW	-	-	-	-	-	30	-	-	-	-	-	845	875
Administration	%	-	-	-	-	-	3.4	-	-	-	-	-	96.6	100.0
City of	MW	-	-	-	-	-	-	-	-	-	8	-	-	8
Bountiful	%	-	-	-	-	-	-	-	-	-	100.0	-	-	100.0
City of	MW	-	-	-	-	-	10	-	-	-	-	-	-	10
Centralia	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
PUD No. 1 of	MW	-	-	-	-	-	1,592	-	-	-	-	-	-	1,592
Chelan County	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
PUD No. 1 of	MW	-	-	-	-	-	58	-	-	-	-	-	-	58
Cowlitz County	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
California-Pacific	MW	-	-	7	-	-	-	-	-	-	-	-	-	7
Utilities	%	-	-	100.0	-	-	-	-	-	-	-	-	-	100.0
PUD No. 1 of	MW	-	-	-	-	-	842	-	-	-	-	-	-	842
Douglas County	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Eugene Water &	MW	-	-	-	7	-	137	-	-	-	-	-	59	203
Electric Board	%	-	-	-	3.4	-	67.5	-	-	-	-	-	29.1	100.0
PUD of Grant	MW	-	-	-	-	-	1,898	-	-	-	-	-	-	1,898
County	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Idaho Power	MW	-	-	-	-	-	1,151	-	-	50	-	-	-	1,201
Company	%	-	-	-	-	-	95.8	-	-	4.2	-	-	-	100.0
Montana Power	MW	-	-	840	73	-	521	-	-	-	-	-	-	1,434
Company	%	-	-	58.6	5.1	-	36.3	-	-	-	-	-	-	100.0
Portland General	MW	1,130	-	-	-	541	660	-	-	-	348	6	-	2,685
Electric Company	%	42.1	-	-	-	20.1	24.6	-	-	-	13.0	0.2	-	100.0

HARZA ENGINEERING COMPANY
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CHICAGO ILLINOIS

DEPARTMENT OF THE ARMY
INSTITUTE FOR WATER RESOURCES
CORPS OF ENGINEERS

THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

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EXISTING GENERATING CAPABILITY

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DATE MARCH, 1979

EXHIBIT X-7

WSCC
NORTHWEST POWER POOL AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		NUCLEAR	STEAM TURBINE Gas	STEAM TURBINE Coal	STEAM TURBINE Oil	Combined Cycle	Hydro	Pumped Storage	COMBUSTION TURBINE Gas	COMBUSTION TURBINE Oil	INTERNAL COMBUSTION Gas	INTERNAL COMBUSTION Oil	OTHERS	TOTAL
Pacific Power & Light Company	MW	-	30	3,550	-	-	863	-	-	28	-	-	-	4,471
	%	-	0.7	79.4	-	-	19.3	-	-	0.6	-	-	-	100.0
Pend Oreille	MW	-	-	-	-	-	78	-	-	-	-	-	-	78
County PUD	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Puget Sound Power & Light Company	MW	-	-	-	86	-	310	-	-	94	-	3	-	493
	%	-	-	-	17.4	-	62.9	-	-	19.1	-	0.6	-	100.0
Seattle Department	MW	-	-	-	36	-	1,466	-	-	-	-	-	-	1,502
of Lighting (Seattle City Light)	%	-	-	-	2.4	-	97.6	-	-	-	-	-	-	100.0
Tacoma Dept. of	MW	-	-	-	-	-	757	-	-	-	-	-	-	757
Public Utilities (Tacoma City Light)	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Utah Power & Light Company	MW	-	66	1,939	24	-	124	-	15	-	-	-	-	2,168
	%	-	3.0	89.5	1.1	-	5.7	-	0.7	-	-	-	-	100.0
Corps of Engineers (North Pacific)	MW	-	-	-	-	-	11,273	-	-	-	-	-	-	11,273
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Bureau of Reclamation (Pacific Northwest)	MW	-	-	-	-	-	4,668	-	-	-	-	-	-	4,668
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Bureau of Reclamation (Upper Colorado)	MW	-	14	-	-	-	10	-	-	-	11	-	-	35
	%	-	40.0	-	-	-	28.6	-	-	-	31.4	-	-	100.0
Washington Water Power Company	MW	-	-	-	-	-	940	-	-	28	-	-	-	968
	%	-	-	-	-	-	97.1	-	-	2.9	-	-	-	100.0
Northwest Power Pool Area	MW	1,130	110	6,336	226	541	27,390	-	15	200	367	11	904	37,230
	%	3.0	0.3	17.0	0.6	1.5	73.7	-	0.04	0.5	1.0	0.03	2.4	100.0

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WSCC
ROCKY MOUNTAIN POWER AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Black Hills Power	MW	-	-	103	-	-	-	-	-	34	-	11	-	148
& Light Company	%	-	-	69.6	-	-	-	-	-	23.0	-	7.4	-	100.0
City of Colorado	MW	-	79	270	-	-	4	-	-	-	-	-	-	353
Springs	%	-	22.4	76.5	-	-	1.1	-	-	-	-	-	-	100.0
City of Lamar	MW	-	37	-	-	-	-	-	-	-	-	2	-	39
	%	-	94.9	-	-	-	-	-	-	-	-	5.1	-	100.0
Colorado-Ute	MW	-	-	500	-	-	26	-	-	-	-	2	-	528
Electric Assn.	%	-	-	94.7	-	-	4.9	-	-	-	-	0.4	-	100.0
Platte River	MW	-	-	-	-	-	1	-	-	-	-	-	-	1
Power Authority	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Public Service	MW	-	72	1,853	124	-	26	162	-	190	-	16	-	2,443
Company of Colorado	%	-	2.9	75.8	5.1	-	1.1	6.6	-	7.8	-	0.7	-	100.0
S. Colorado Power	MW	-	43	43	-	-	-	-	-	-	-	20	-	106
Div. Central Tele.	%	-	40.6	40.6	-	-	-	-	-	-	-	18.8	-	100.0
& Utility														
Tri-State G & T	MW	-	-	-	-	-	-	-	-	314	-	-	-	314.
Association, Inc.	%	-	-	-	-	-	-	-	-	100.0	-	-	-	100.0
Bureau of Reclama-	MW	-	-	-	-	-	563	-	-	-	-	-	-	563
tion (Lower Missouri)	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Bureau of Reclama-	MW	-	30	-	-	-	1,462	-	-	-	4	-	-	1,496
tion (Upper Colorado)	%	-	2.0	-	-	-	97.7	-	-	-	0.3	-	-	100.0
Region														
Rocky Mountain	MW	-	261	2,769	124	-	2,082	162	-	538	4	51	-	5,991
Power Area	%	-	4.4	46.1	2.1	-	34.7	2.7	-	9.0	0.1	0.9	-	100.0

WSCC
ARIZONA-NEW MEXICO POWER AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Arizona El. Power Cooperative, Inc.	MW	-	-	-	-	85	-	-	-	83	-	-	-	168
	%	-	-	-	-	50.6	-	-	-	49.9	-	-	-	100.0
Arizona Public Service Company	MW	-	-	2,288	627	225	5	-	-	512	-	-	-	3,567
	%	-	-	62.6	17.1	6.2	0.1	-	-	14.0	-	-	-	100.0
Citizens Utility Company	MW	-	-	-	-	-	-	-	-	-	-	3	-	3
	%	-	-	-	-	-	-	-	-	-	-	100.0	-	100.0
El Paso Electric Company	MW	-	300	-	326	224	-	-	-	-	-	-	-	850
	%	-	35.3	-	38.4	26.3	-	-	-	-	-	-	-	100.0
Imperial Irrigation District	MW	-	-	-	180	-	39	-	-	98	-	12	-	329
	%	-	-	-	54.6	-	11.9	-	-	29.9	-	3.6	-	100.0
Los Alamos Systems	MW	-	16	-	-	-	-	-	-	-	-	-	-	16
	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Plains Elec. Gen. & Trans. Coop.	MW	-	45	-	-	-	-	-	-	-	-	-	-	45
	%	-	100.0	-	-	-	-	-	-	-	-	-	-	100.0
Public Service Co. of New Mexico	MW	-	304	652	-	-	-	-	20	-	-	-	-	976
	%	-	31.1	66.9	-	-	-	-	2.0	-	-	-	-	100.0
San Carlos Irrigation Project	MW	-	-	-	-	-	10	-	-	-	-	-	-	10
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Salt River Project	MW	-	-	2,250	534	288	92	140	-	378	-	-	-	3,682
	%	-	-	61.1	14.5	7.8	2.5	3.8	-	10.3	-	-	-	100.0
Tucson Gas & Electric Company	MW	-	-	-	520	-	-	-	-	219	-	-	-	739
	%	-	-	-	70.4	-	-	-	-	29.6	-	-	-	100.0
Bureau of Reclamation (Lower Colorado Region)	MW	-	-	-	-	-	530	-	-	-	-	-	-	530
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Bureau of Reclamation (Southwest Region)	MW	-	-	-	-	-	15	-	-	-	-	-	-	15
	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Arizona-New Mexico Power Area	MW	-	665	5,190	2,187	822	691	140	20	1,290	-	15	-	11,020
	%	-	6.0	47.1	19.8	7.6	6.3	1.3	0.2	11.7	-	0.1	-	100.0

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WSCC
SOUTHERN CALIFORNIA-NEVADA POWER AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
City of Burbank	MW	-	-	-	169	-	-	-	-	-	-	-	77	246
	%	-	-	-	68.7	-	-	-	-	-	-	-	31.3	100.0
Dept. of Water	MW	-	-	-	-	-	120	-	-	-	-	-	-	120
Resources/California	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Glendale Public	MW	-	-	-	117	98	-	-	-	53	-	-	-	268
Service Department	%	-	-	-	43.6	36.6	-	-	-	19.8	-	-	-	100.0
Los Angeles Dept.	%	-	309	-	2,915	-	948	985	-	76	-	-	-	5,233
Water and Power	%	-	5 9	-	55.7	-	18.1	18.8	-	1.5	-	-	-	100.0
Metropolitan Water	MW	-	-	-	-	-	261	-	-	-	-	-	-	261
Dist./S. California	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Nevada Power	MW	-	276	330	-	-	-	-	128	-	-	30	-	764
Company	%	-	36.1	43.2	-	-	-	-	16.8	-	-	3.9	-	100.0
City of Pasedena	mW	-	-	-	220	-	15	-	-	52	-	-	-	287
	%	-	-	-	76.7	-	5.2	-	-	18.1	-	-	-	100.0
Southern California	MW	436	-	1,580	8,858	479	1,132	-	-	550	-	-	-	13,035
Edison Company	%	3.3	-	12.1	68.0	3.7	8.7	-	-	4.2	-	-	-	100.0
San Diego Gas &	MW	-	-	-	1,608	-	-	-	-	316	-	-	18	1,942
Electric Company	%	-	-	-	82.8	-	-	-	-	16.3	-	-	0.9	100.0
State of Nevada	MW	-	10	-	-	-	-	-	15	-	-	-	-	25
	%	-	40.0	-	-	-	-	-	60.0	-	-	-	-	100.0
Southern California Nevada Power Area	MW	436	595	1,910	13,887	577	2,476	985	143	1,047	-	30	95	22,181
	%	2.0	2.7	8.6	62.7	2.6	11.2	4.4	0.6	4.7	-	0.1	0.4	100.0

HARZA ENGINEERING COMPANY
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THE MAGNITUDE AND REGIONAL DISTRIBUTION
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WSCC
NORTHERN CALIFORNIA-NEVADA POWER AREA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
City and County of	MW	-	-	-	-	-	313	-	-	-	-	-	-	313
San Francisco	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Dept. of Water	MW	-	-	-	-	-	434	606	-	-	-	-	-	1,040
Resources/California	%	-	-	-	-	-	41.7	58.3	-	-	-	-	-	100.0
Pacific Gas &	MW	63	-	-	7,488	-	3,357	-	-	241	-	-	502	11,651
Electric Company	%	0.5	-	-	64.3	-	28.8	-	-	2.1	-	-	4.3	100.0
Sacramento Munici-	MW	875	-	-	-	-	653	-	-	-	-	-	-	1,528
pal Utility District	%	57.3	-	-	-	-	42.7	-	-	-	-	-	-	100.0
Sierra Pacific	MW	-	466	-	-	-	12	-	15	22	2	50	-	567
Power Company	%	-	82.2	-	-	-	2.1	-	2.6	3.9	0.4	8.8	-	100.0
Turlock & Modes to	MW	-	-	-	-	-	148	-	-	-	-	-	-	148
Irrigation District	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Bureau of Reclama-	MW	-	-	-	-	-	1,260	-	-	-	-	-	-	1,260
tion (Mid-Pacific Region)	%	-	-	-	-	-	100.0	-	-	-	-	-	-	100.0
Northern California	MW	938	466	-	7,488	-	6,177	606	15	263	2	50	502	16,507
Nevada Power Area	%	5.7	2.8	-	45.4	-	37.4	3.7	0.1	1.6	0.01	0.3	3.0	100.0

HARZA ENGINEERING COMPANY
DEPARTMENT OF THE ARMY

WSCC
EXISTING GENERATING CAPABILITY

MARCH, 1979
EXHIBIT X-7

WSCC
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

			STEAM TURBINE			Combined		Pumped	COMBUSTION TURBINE		INTERNAL COMBUSTION			
		NUCLEAR	Gas	Coal	Oil	Cycle	Hydro	Storage	Gas	Oil	Gas	Oil	OTHERS	TOTAL
Northwest Power Pool Area	MW	1,130	110	6,336	226	541	27,390	-	15	200	367	11	904	37,230
	%	3.0	0.3	17.0	0.6	1.5	73.7	-	0.04	0.5	1.0	0.03	2.4	100.0
Rocky Mountain Power Area	MW	-	261	2,769	124	-	2,082	162	-	538	4	51	-	5,991
	%	-	4.4	46.1	2.1	-	34.7	2.7	-	9.0	0.1	0.9	-	100.0
Arizona - New Mexico Power Area	MW	-	665	5,190	2,187	822	691	140	20	1,290	-	15	-	11,020
	%	-	6.0	47.0	19.8	7.6	6.3	1.3	0.2	11.7	-	0.1	-	100.0
Southern California Nevada Power Area	MW	436	595	1,910	13,887	577	2,476	985	143	1,047	-	30	95	22,181
	%	2.0	2.7	8.6	62.7	2.6	11.2	4.4	0.6	4.7	-	0.1	0.4	100.0
Northern California Nevada Power Area	MW	938	466	-	7,488	-	6,177	606	15	263	2	50	502	16,507
	%	5.7	2.8	-	45.4	-	37.4	3.7	0.1	1.6	0.01	0.3	3.0	100.0
WSCC Total	MW	2,504	2,097	16,205	23,912	1,940	38,816	1,893	193	3,338	373	157	1,501	92,929
	%	2.7	2.3	17.4	25.7	2.1	41.8	2.0	0.2	3.6	0.4	0.2	1.6	100.0

Source: Based on summer generating capability reported to the Department of Energy, FERC (FPC) Order 383-5, Docket R-362, April 1978.

WSCC
EXISTING GENERATING CAPABILITY

DATE MARCH, 1979
EXHIBIT X-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND ALASKA REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ALASKA**	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT XI–1

ALASKA - REPORTING UTILITIES

Leter Code	
ALEL	Alaska Electric Light and Power Company
ANCO	Anchorage Municipal Light and Power Dept.
APAD-E	Alaska Power Administration-Eklutna (Anchorage)
APAD-S	Alaska Power Administration-Snettisham (Juneau)
APCO	Aniak Power Company
APTC	Alaska Power & Telephone Company
AVEC	Alaska Village Electric Cooperative, Inc.
BAUI	Barrow Utilities, Incorporated
BUCI	Bethel Utilities Corporation, Inc.1/
BLPI	Bettles Light & Power, Inc.
CICU	Circle City Utilities
CHEA	Chaugach Electric Association, Inc.
COHU	City of Hoonah
COKE	Community of Kake
COUU	City of Unalaska
CPCO	Chitina Power Co., Inc.
COPU	Cordova Public Utilities
CRTP	Chistochina Trading Post
CVEA	Copper Valley Electric Association, Inc.
DLEI	Dot Lake Electric, Inc.
FACO	Fairbanks Municipal Utilities System
FYUI	Fort Yukon Utilities
GHEA	Glacier Highway Electric Association, Inc.
GOVE	Golden Valley Electric Association, Inc.
HOEA	Homer Electric Association, Inc.
HLPC	Haines Light and Power Co., Inc.
	Hoonah (See COHU)
	Kake (See COKE)
KLCM	Klawock, City of
KECO	Ketchikan Public Utilities
KOEA	Kodiak Electric Association, Inc.
KTEA	Kotzebue Electric Association, Inc.
	Lake Minchumina (See SESU)
MEAI	Matanuska Electric Association, Inc.
MHSE	Manley Hot Springs Enterprises
MPLM	Metlakatla Power and Light
NCCO	Northern Commercial Company
NEAI	Naknek Electric Association, Inc.
NECI	Nushagak Electric Cooperative, Inc.
NLPU	Nome Light and Power Utilities

ALASKA - REPORTING UTILITIES (Cont'd)

Letter Code	
NPEC	Northern Power & Engineering Coporation, Inc.
NPLI	Northway Power & Light, Inc.
PALI	Paxson Lodge, Inc.
PMLP	Petersburg Municipal Light and Power
PUCO	Pelican Utility Company
SESM	Seward Electric System
SESU	Semloh Supply (Lake Minchumina)
SIPU	Sitka Electric Department
TLPU	Teller Light and Power Utilities
TTPC	Teller Telephone & Power Company, Inc.
TPCO	Tanana Power Company
	Unalaska (See COUU)
WRLD	Wrangell Municipal Light & Power
WTCO	Weisner Trading Co.
YAPI	Yakutat Power, Inc.

1/ Owned by Northern Power and Engineering Corporation of Anchorage.

SOURCE: "The 1976 Alaska Power Survey" FPC, Volume 1.

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THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **ALASKA** **LIST OF UTILITIES** **PAGE 2 OF 2**	
CONTRACT NO. DACW72 - 78 - C - 0013 DATE MARCH, 1979	EXHIBIT XI-2

ALASKA[1/]

ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR

Calendar Year	Annual Energy[2/] GWh	Average Annual Growth Rate-% 1 yr	Average Annual Growth Rate-% 5 yr	Peak Demand Peak MW	Average Annual Growth Rate-% 1 yr	Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
1965	578.5	-	-	127.6	-	-	51.8
1966	647.6	11.9	-	140.5	10.1	-	52.6
1967	711.9	9.9	-	149.3	6.3	-	54.4
1968	798.3	12.1	-	182.9	22.5	-	49.7[3/]
1969	895.5	12.2	-	185.6	1.5	-	55.1
1970	1,043.9	16.6	12.5	234.4	26.3	12.9	50.8
1971	1,239.9	18.8	13.9	263.0	12.2	13.4	53.8
1972	1,404.3	13.3	14.6	288.4	9.7	14.1	55.4[3/]
1973	1,545.6	10.1	14.1	294.7	2.2	10.0	59.9
1974	1,667.1	7.9	13.2	345.2	17.1	13.2	55.1
1975	1,979.4	18.7	13.7	453.2	31.3	14.1	49.9
1976	NA	-	-	NA	-	-	-
1977	2,261.9	-	10.0	538.0	-	13.3	48.0

1/ Utilities considered are from the Southeast, Southcentral, and Yukon Interior regions, which represent approximately 3/4 of the total state wide demand.

2/ Annual energy sales.

3/ Load factor based on 8,784 hours.

SOURCE: Alaska Electric Power Statistics, 1960-1975.

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ALASKA

ELECTRIC POWER DEMAND

CONTRACT NO. DACW 72-78-C-0018

DATE MARCH, 1979

EXHIBIT XI-3

ALASKA

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

YEAR	RESIDENTIAL	COMMERICAL 2/	INDUSTRIAL 1/	TOTAL
1965	9.5	9.4	11.5	9.7
1966	9.4	11.9	23.5	12.1
1967	14.9	12.5	0.0	12.0
1968	5.2	5.5	3.6	5.1
1969	13.9	16.4	6.9	14.2
1970	11.5	9.5	7.5	10.3
1971	16.8	12.6	9.0	14.2
1972	3.5	4.5	11.9	4.7
1973	32.2	28.6	17.2	29.1
1974	3.0	3.0	7.0	3.4

SOURCE: United States Department of the Interior. Alaska Power Administration "Alaska Electric Power Statistics 1960-1975" 4th ed. (July 1976).

1/ Reported in Source as "Commerical and Industrial-Large Light and Powers".

2/ Reported in Source as "Commerical and Industrial-Small Light and Power.

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THE NATIONAL HYDROPOWER STUDY

ALASKA

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

CONTRACT NO. [illegible]

DATE MARCH, 1979

EXHIBIT XI – 4

ALASKA
SYSTEM LOAD VARIATIONS[1]
1977

Representative Utilities	First Week of April		First Week of August		First Week of December		Annual			
	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand % of Annual	Weekly Load Factor %	Peak Demand MW	Date	Net Energy GWh	Load Factor %
Fairbanks Municipal Utilities System	75.4	76.4	68.1	79.1	94.2	83.7	27.6	Dec 12	128.5	53.1
Chugach Electric Association, Inc.	61.4	78.9	47	83.6	97.6	88.1	274.0	Dec 5	1236.5	51.5
Golden Valley Electric Association, Inc.	54.4	81.4	38.8	77.9	91.4	87.1	89.9	Dec 13	353.1	45.0
Kodiak Electric Association, Inc.	78.2[3]	68.6[4]	80.2	63.4[4]	90.1	61.5[4]	10.1	Nov 5	53.6	60.6
Sitka Electric Department	88.9[3]	67.6[4]	80.2[3]	73.0[4]	NA	NA	8.1[2]	Nov 29	44.0	NA

NA - Not Available

1/ Computations based on data from schedules 14 and 15 of 1977 FERC-Form 12.
2/ Does not include December 1977.
3/ Monthly Peak.
4/ Monthly Load Factor.

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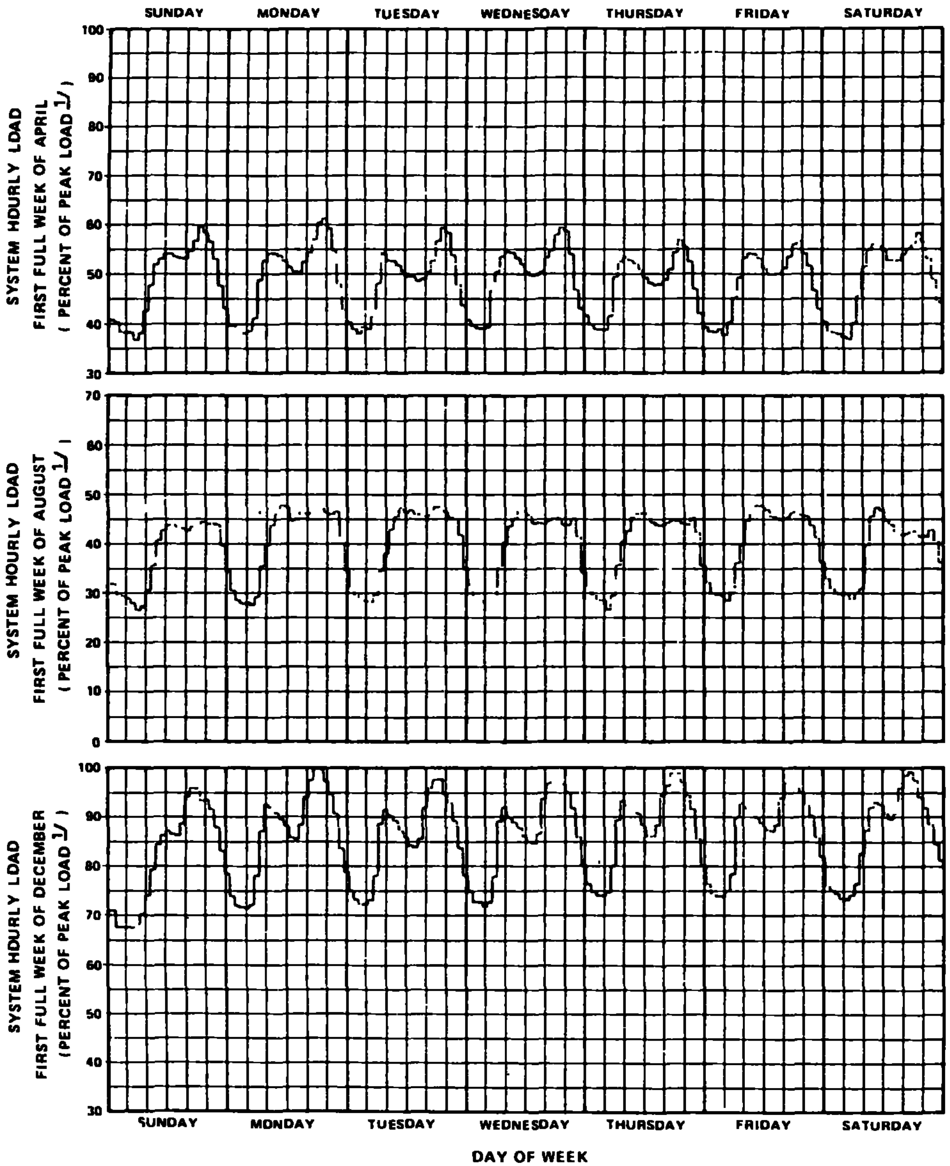
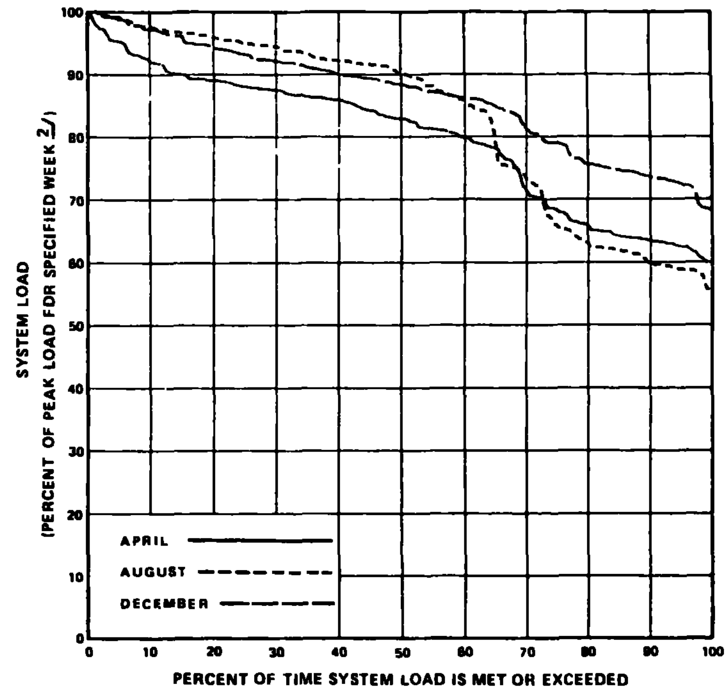
ALASKA
SYSTEM LOAD VARIATIONS, 1977

CONTRACT NO. DACW72-78-C-0011
DATE MARCH, 1979
EXHIBIT XI-5





NOTES.

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL AUGUST, OR DECEMBER CURVES

SOURCE

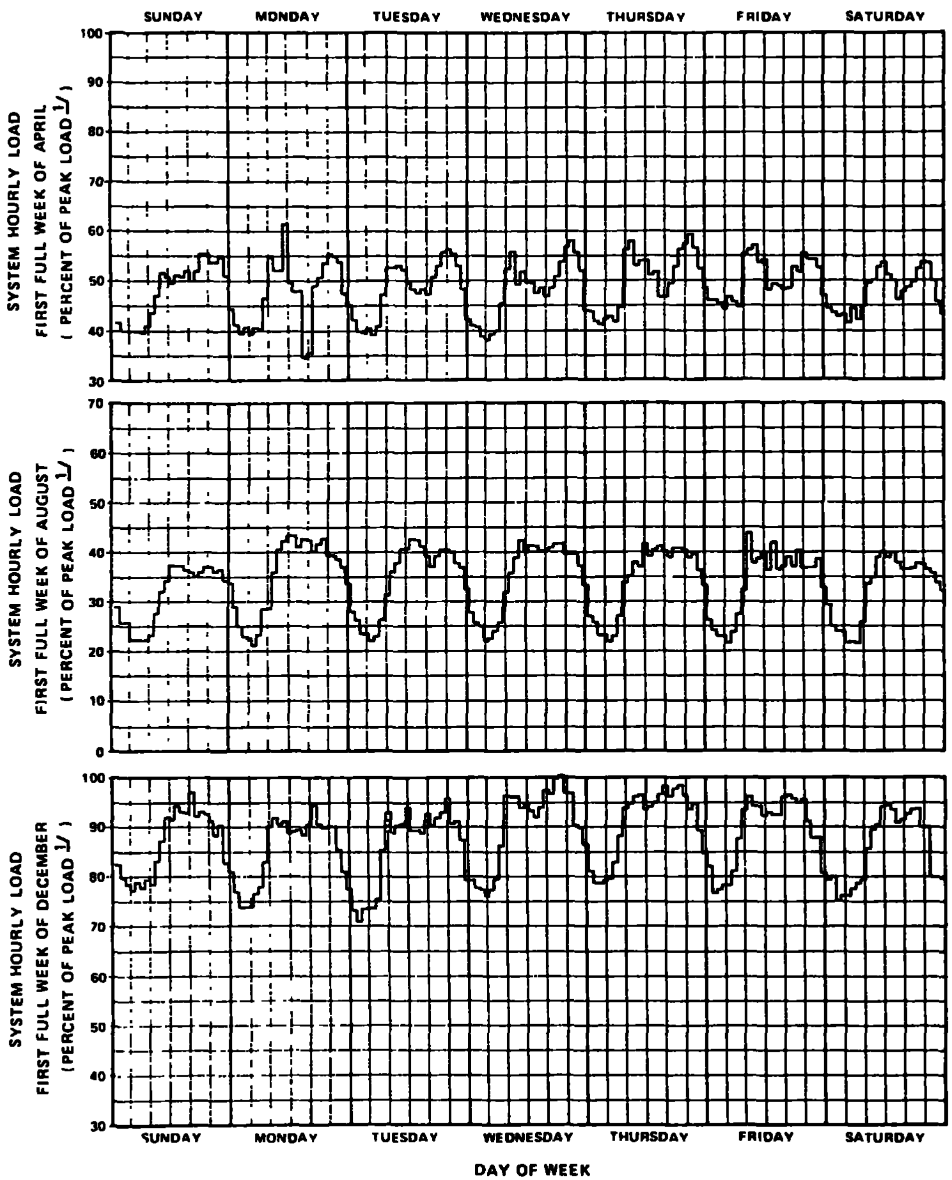
DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

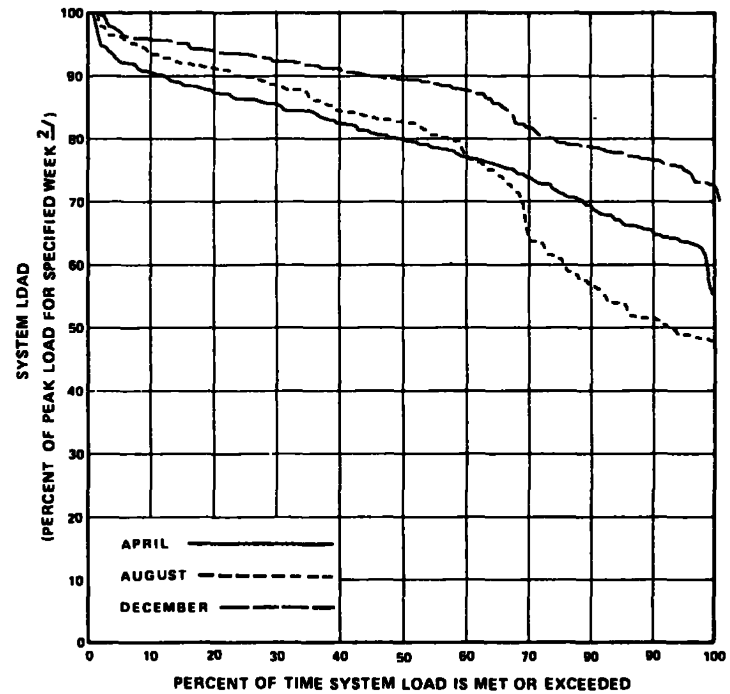
LOAD CURVES

REGION ALASKA
SUB-REGION ALASKA
UTILITY CEA
SHEET 1 OF 3

MARCH

EXHIBIT XI-6





NOTES:

1. PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2. PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

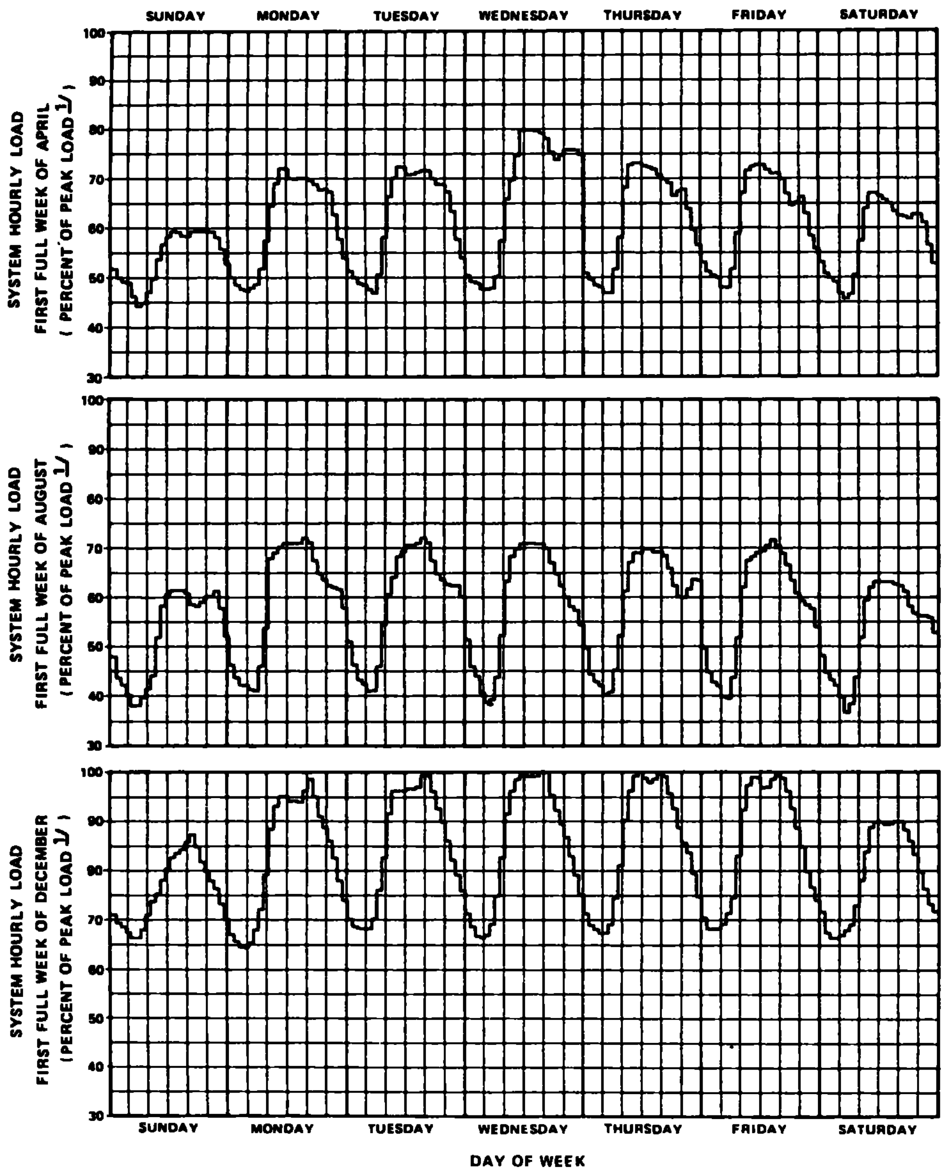
DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

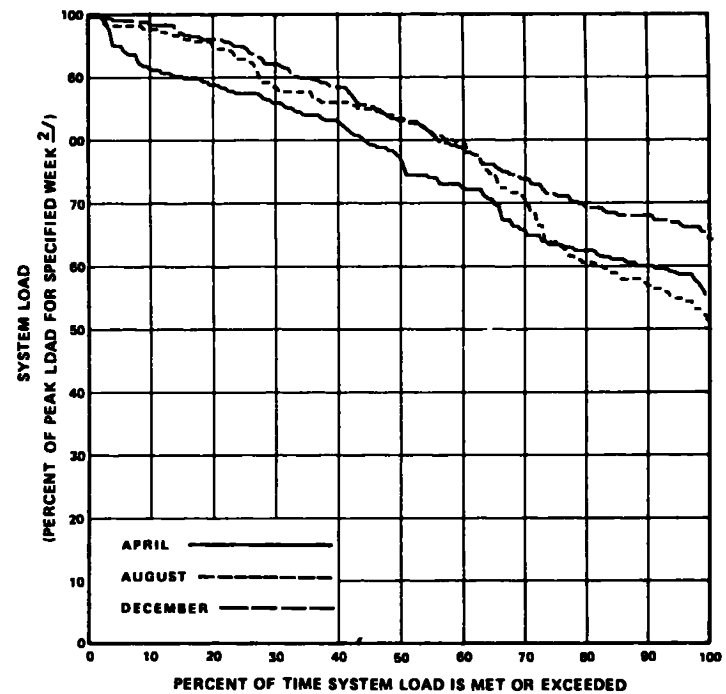
LOAD CURVES

REGION ALASKA
SUB-REGION ALASKA
UTILITY GVEA
SHEET 2 OF 3

MARCH 1979

EXHIBIT XI-6





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES
REGION ALASKA
SUB-REGION ALASKA
UTILITY FMU
SHEET 3 OF 3

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EXHIBIT XI-6

ALASKA
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS 1/
(1977)

		Steam Turbine	Combustion Turbine	Hydro	Internal Combustion	Total
Southeast Sub-Region	MW	-	-	80.5	58.5	139.0
	%	-	-	57.9	42.1	100.0
Southcentral Sub-Region	MW	29.5	475.2	51.0	58.0	613.7
	%	4.8	77.4	8.3	9.5	100.0
Southwest Sub-Region	MW	-	-	-	18.9	18.9
	%	-	-	-	100.0	100.0
Yukon Sub-Region	Mw	53.5	172.1	-	44.6	270.2
	%	19.8	63.7	-	16.5	100.0
Northwest Sub-Region	MW	-	-	-	11.8	11.8
	%	-	-	-	100.0	100.0
Arctic Sub-Region	MW	-	1.5	-	1.2	2.7
	%	-	55.6	-	44.4	100.0
Alaska Total	MW	83.0	648.8	131.5	193.0	1056.3
	%	7.9	61.4	12.4	18.3	100.0

Source: 1976 Alaska Power Survey, Vol. I, F.P.C.

1/ Data in this table projected from 1975 data as presented in the above source.

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THE NATIONAL HYDROPOWER STUDY

ALASKA

EXISTING GENERATING CAPABILITY

CONTRACT NO DACW72 - 78 - C - 0013
DATE MARCH, 1979

EXHIBIT XI-7

FOR OUTLINE OF REGION, SEE EXHIBIT I-1
AND HAWAII REGIONAL REPORT

HARZA ENGINEERING COMPANY CONSULTING ENGINEERS CHICAGO, ILLINOIS	DEPARTMENT OF THE ARMY INSTITUTE FOR WATER RESOURCES CORPS OF ENGINEERS
THE MAGNITUDE AND REGIONAL DISTRIBUTION OF NEED FOR HYDROPOWER THE NATIONAL HYDROPOWER STUDY **HAWAII**	
CONTRACT NO DACW72 – 78 – C – 0013 DATE MARCH, 1979	EXHIBIT XII–1

HAWAII
OWNERSHIP OF GENERATION SOURCES
January 1, 1978

		Island	Investor Owned	Cooperative
I.	Electric Utilities			
	1. Hawaiian Electric Company	Oahu	x	
	Hawaii Electric Light Company	Hawaii	x	
	Maui Electric Company	Maui-Lanai	x	
	2. Kauai Electric Division, Citizens Utility Company	Kauai	x	
	3. Molokai Electric Company	Molokai	x	
II.	Agriculture Processing Companies			
	1. C. Brewer & Company, Ltd			
	Wailuku Sugar Company	Maui	x	
	Olokele Sugar Company	Kauai	x	
	Ka'u Sugar Company	Hawaii	x	
	Hilo Coast Processing Company			
	Hilo	Hawaii	x	x
	Onomea	Hawaii	x	x
	Pepeekeo	Hawaii	x	x
	2. Castle & Coske, Inc.			
	Waialua Sugar Company	Oahu	x	
	Lanai Diesel Generating Plant (Dole)	Lanai	x	
	Kohala Sugar Company	Hawaii	x	
	3. Theo H. Davies & Company, Ltd.			
	Honokaa Sugar Company	Hawaii	x	
	Laupahoehoe Sugar Company	Hawaii	x	
	4. Alexander & Baldwin, Ltd.			
	McBryde Sugar Co., Ltd.			
	Hawaiian Commercial & Sugar Company	Maui	x	
	5. Ampac, Inc.			
	Lihue Planation Company, Ltd.	Kanai	x	
	Kekaha Sugar Company, Ltd.	Kanai	x	
	Oahu Sugar Company, Ltd.	Oahu	x	
	Pioneer Mill Company, Ltd.	Maui	x	
	Puna Sugar Company, Ltd.	Hawaii	x	
	6. California and Hawaiian Sugar Company	Oahu		x

SOURCE: U.S. Army Engineer District, Harbors and Rivers in Hawaii, "Hydroelectric Power, Plan Study", Honolulu, September 1977.

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HAWAII

LIST OF UTILITIES

CONTRACT NO DACW72-78-C-0013
DATE MARCH, 1979

EXHIBIT XII-2

HAWAII[1]
ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR

Calendar Year	Annual Energy: Thousands of GWh[2]	Annual Energy: Average Annual Growth Rate-% 1 yr	Annual Energy: Average Annual Growth Rate-% 5 yr	Peak Demand: Peak[3] MW	Peak Demand: Average Annual Growth Rate-% 1 yr	Peak Demand: Average Annual Growth Rate-% 5 yr	Annual Load Factor-%
1970	3,870	-	-	765	-	-	57.7
1971	4,264	10.2	-	821	7.3	-	59.3
1972	4,626	8.5	-	885	7.8	-	59.7
1973	4,909	6.1	-	929	5.0	-	60.3
1974	5,137	4.6	-	962	3.6	-	61.0
1975	5,309	3.3	6.5	985	2.4	5.2	61.5
1976	5,633	6.1	5.7	1,044	6.0	5.0	61.6
1977	5,855	3.9	4.8	1,073	2.8	4.0	62.3

SOURCE: 1974 & 1977 annual reports for Hawaiian Electric Company, Inc.

1/ Includes data from the Hawaiian Electric Company, Inc., and its subsidiaries, which are Hawaiian Electric Light Company and Maui Electric Company.

2/ Represents net generated energy, which excludes purchased energy.

3/ Noncoincident and nonintegrated.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

HAWAII
ELECTRIC POWER DEMAND

CONTRACT NO. DACW72-[illegible]
DATE MARCH, 1979

EXHIBIT XII-3

HAWAII
ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES
(Percentage)

Hawaiian Electric Co., Inc.[1/]	Residential	Commercial	Industrial	Total
1970				
1971	8.2	8.5	14.1	11.0
1972	8.7	9.3	10.3	9.6
1973	5.8	11.6	5.4	6.7
1974	3.5	3.6	7.1	5.2
1975	2.3	6.6	4.5	4.2
1976	4.3	9.3	4.3	5.3
1977	1.5	6.5	3.9	3.7

SOURCE: Computed from the annual reports for the above company.

1/ Includes the subsidiaries of Hawaiian Electric Company, Inc., which are Hawaiian Electric Light Company and Maui Electric Company.

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OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

HAWAII

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION

CONTRACT NO DACW72-78-C-0013
DATE MARCH, 1979

EXHIBIT XII – 4

HAWAII
SYSTEM LOAD VARIATIONS 1/
1977

Representative Utilities	First Week of April: Peak Demand % of Annual	First Week of April: Weekly Load Factor %	First Week of August: Peak Demand % of Annual	First Week of August: Weekly Load Factor %	First Week of December: Peak Demand % of Annual	First Week of December: Weekly Load Factor %	Annual: Peak Demand MW	Annual: Date	Annual: Net Energy GWh	Annual: Load Factor %
Hawaii Electric Light Co., Inc. 2/	90.9	71.1	85.7	75.0	92.2	71.1	80.5	Nov 30	421.61	59.8
Hawaiian Electric Co. Inc.	89.1	74.2	91.3	78.8	98.9	75.1	904.9	Dec 12	5210.0	69.2
Maui Electric Co., Ltd. 2/	81.6	71.0	91.2	73.0	92.1	65.0	72.4	Dec 29	377.68	59.6
Citizens Utilities Co. - Kauai Electric Div.	78.9	75.3	89.3	76.7	89.0	68.1	33.7	Nov 29	182.99	62.0

1/ Computations based on data from schedules 14 and 15 of 1977 FERC - Form 12

2/ Subsidiary of Hawaiian Electric Co., Inc.

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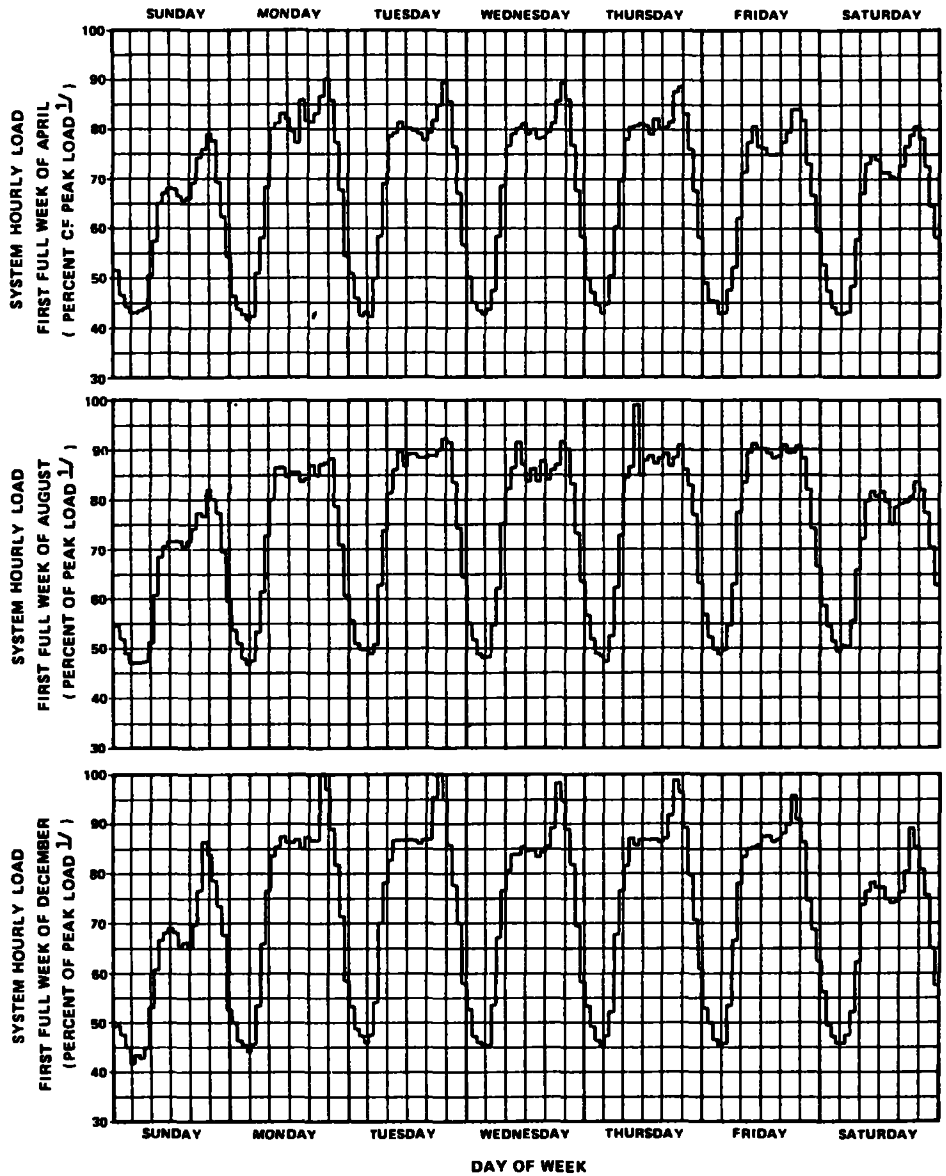
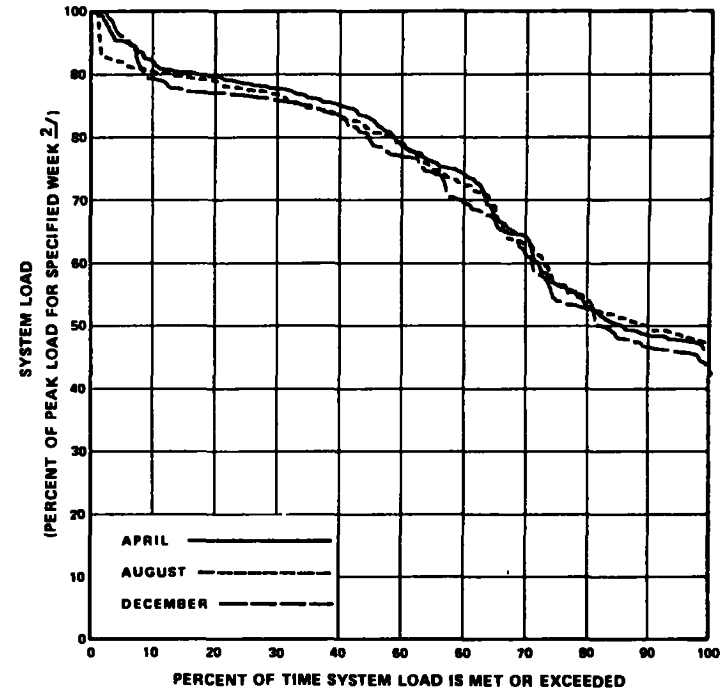
THE MAGNITUDE AND REGIONAL DISTRIBUTION
OF NEED FOR HYDROPOWER
THE NATIONAL HYDROPOWER STUDY

HAWAII
SYSTEM LOAD VARIATIONS, 1977

DATE: MARCH, 1979

EXHIBIT XII – 5





NOTES

1 PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER

2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES.

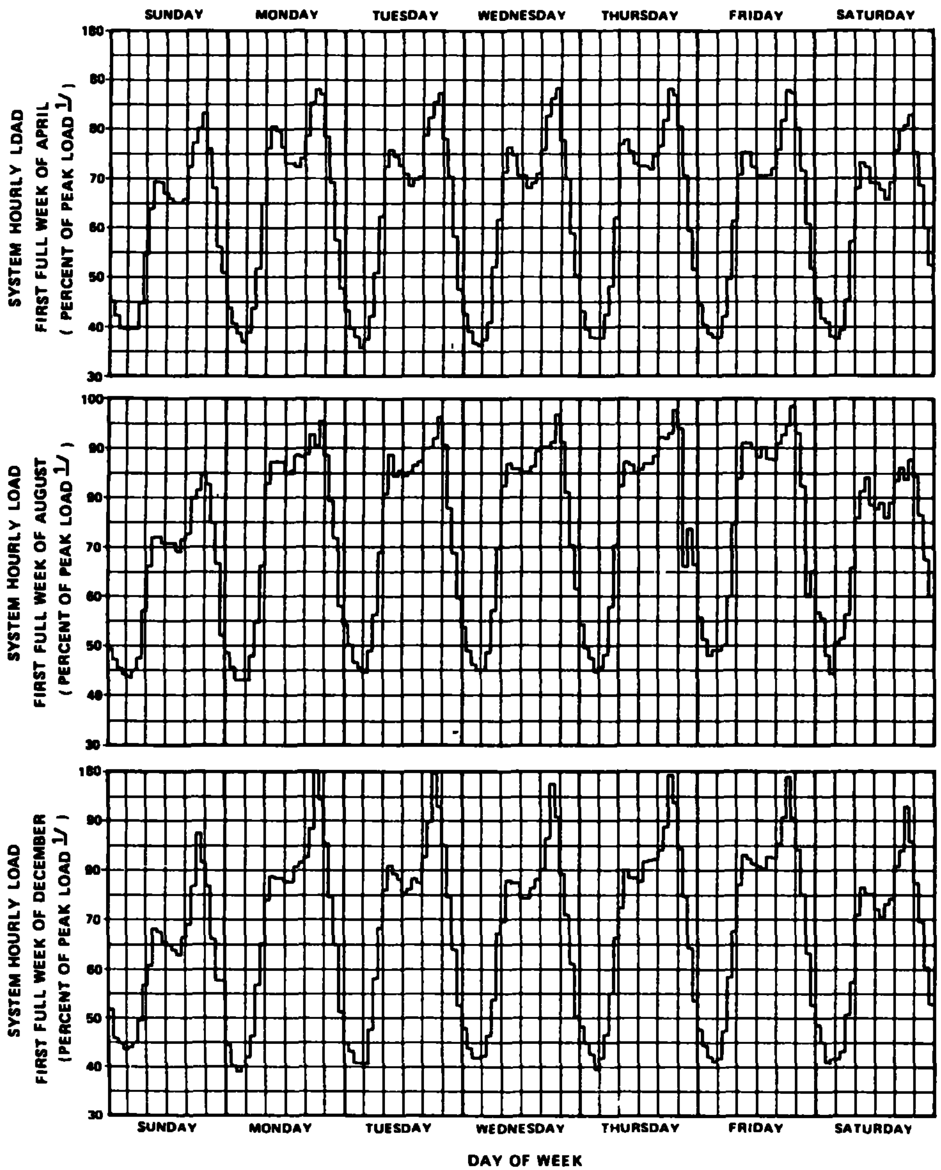
SOURCE.

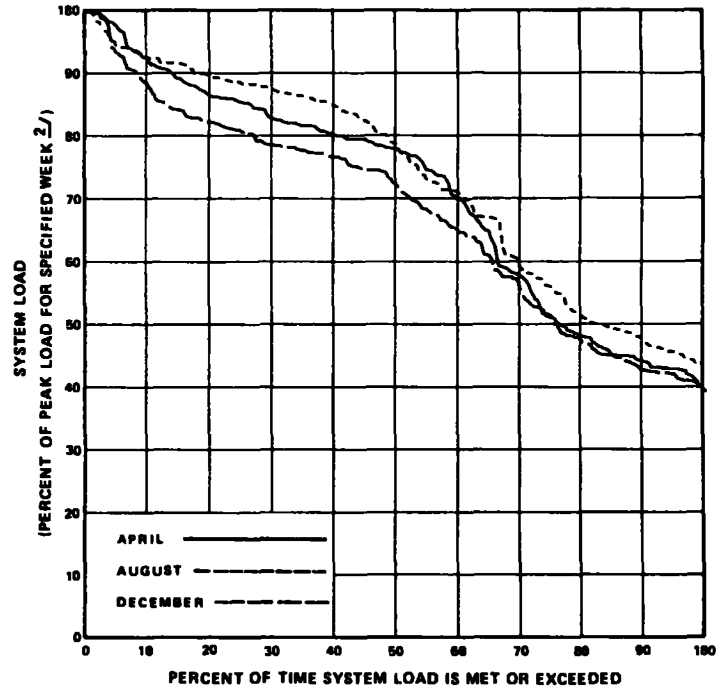
DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES
REGION: HAWAII
SUB-REGION HAWAII
UTILITY HECO
SHEET 1 OF 4

DATE MARCH, 1979

EXHIBIT XII-6





NOTES·

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION HAWAII

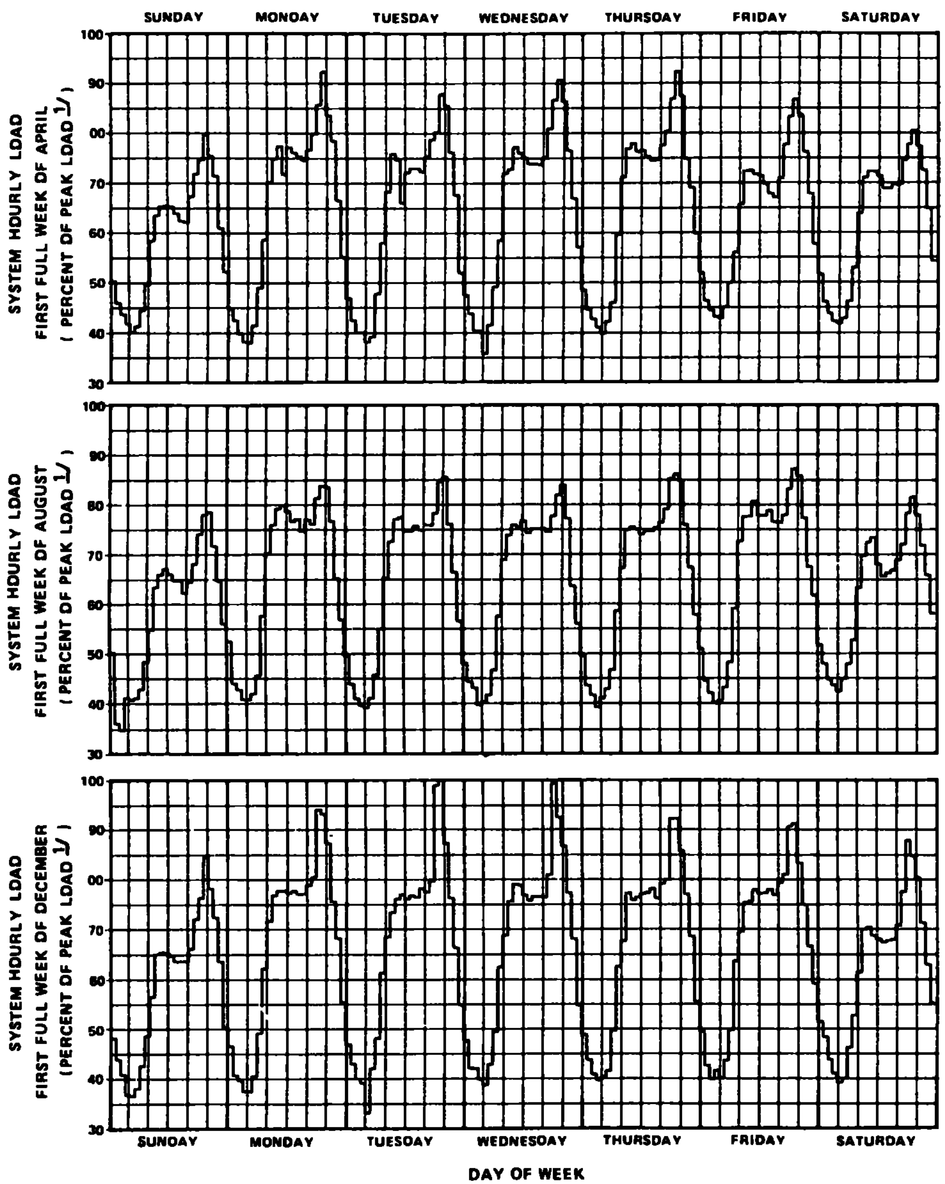
SUB-REGION HAWAII

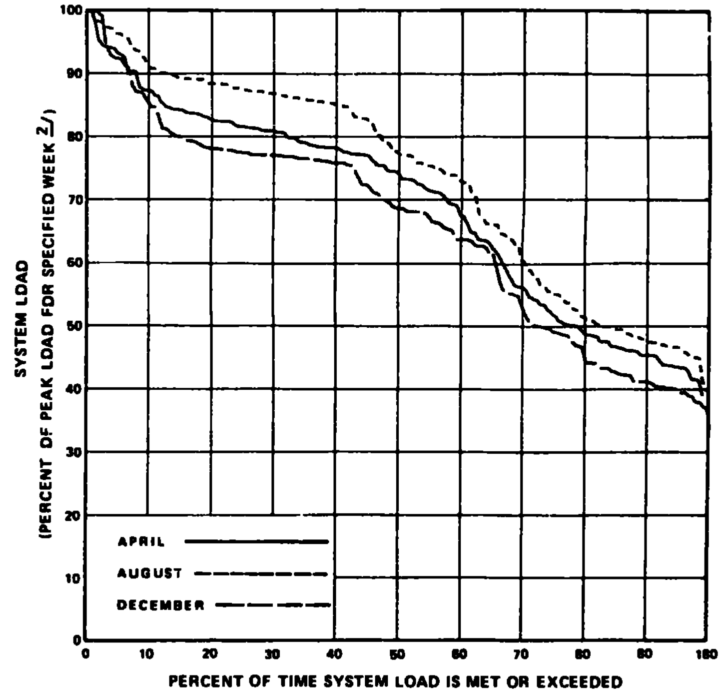
UTILITY HEC

SHEET 2 OF 4

MARCH 1979

XII-6





NOTES.

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2 PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION: HAWAII
SUB-REGION: HAWAII
UTILITY: HELC

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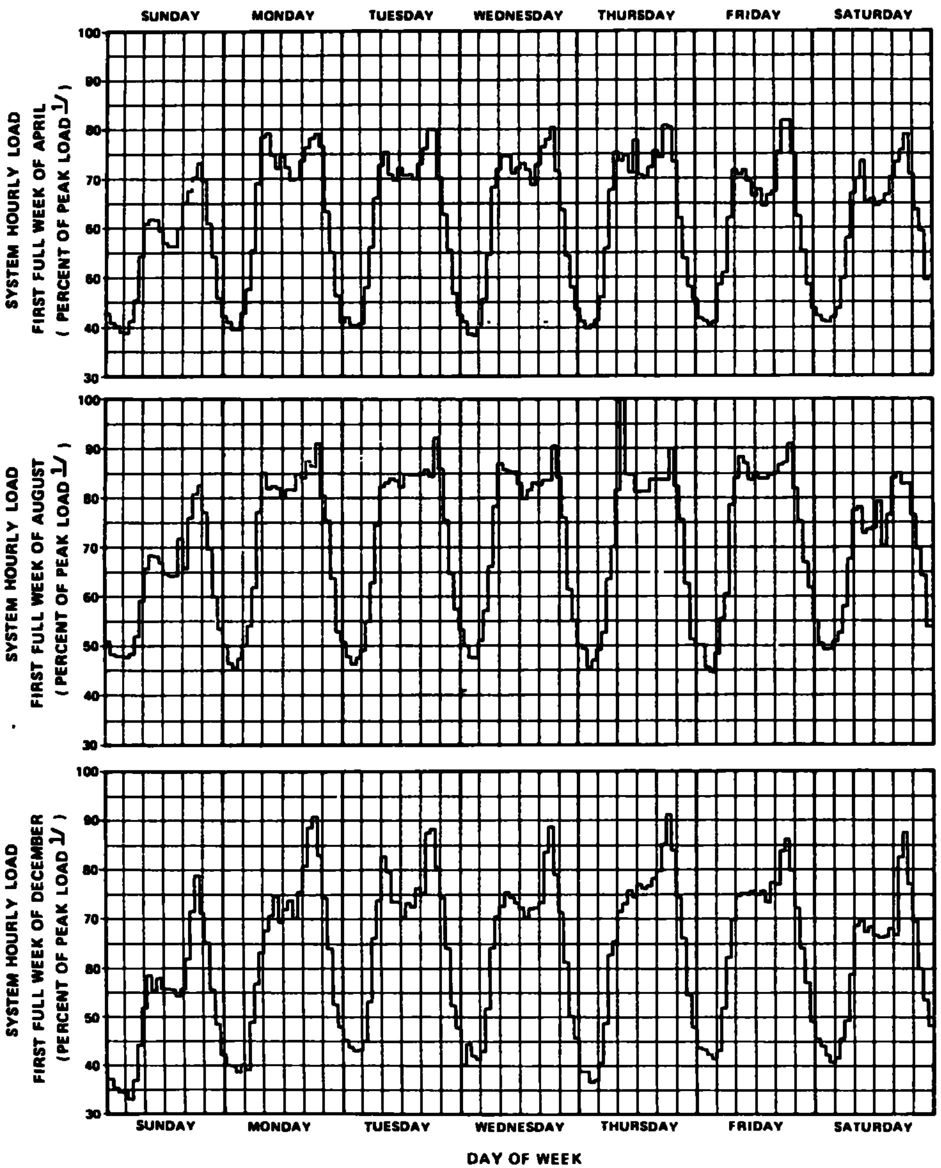
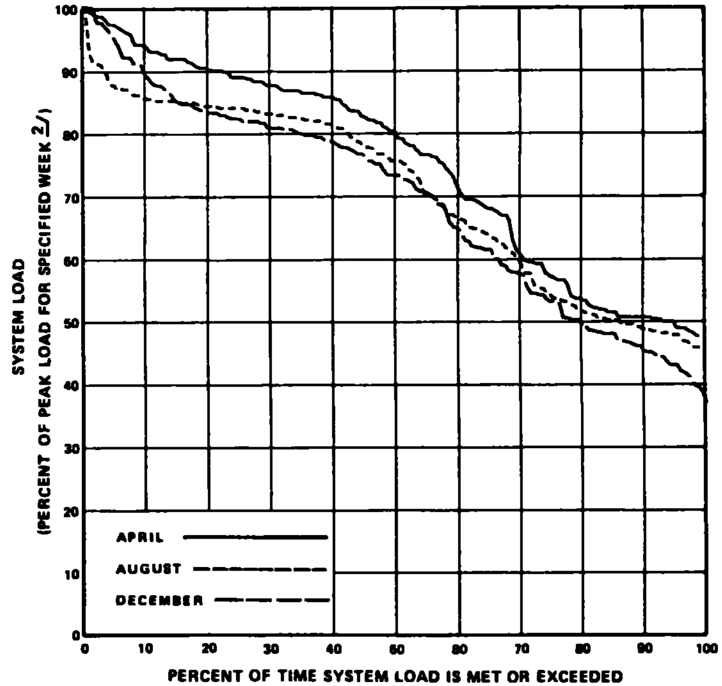
DATE MARCH, 1979

EXHIBIT XII-6





NOTES.

1. PEAK LOAD IS EQUAL TO THE LARGEST SYSTEM LOAD IN THE FIRST FULL WEEK OF APRIL, AUGUST, AND DECEMBER
2. PEAK LOAD IS THE PEAK SYSTEM LOAD FOR THE CORRESPONDING WEEK FOR THE APRIL, AUGUST, OR DECEMBER CURVES

SOURCE

DATA OBTAINED FROM FERC FORM NO 12 (SCHEDULES 14 AND 15) FOR 1977

LOAD CURVES

REGION HAWAII
SUB-REGION HAWAII
UTILITY CIUC

SHEET 4 OF 4

MARCH 1979

XII-6

HAWAII
EXISTING GENERATING CAPABILITY BY TYPES OF PLANTS
(As of January 1, 1978)

		Steam Turbine	Hydro	Combustion Turbine	Internal Combustion[1/]	Total
Hawaii Electric Light Co., Inc.	MW	58.9	3.4	10.6	29.8	102.7
	%	57.4	3.3	10.3	29.0	100.0
Hawaiian Electric Co.,Inc.	MW	1,104	-	105.4	-	1,209.4
	%	91.3	-	8.7	-	100.0
Maui Electric Co., Ltd.	MW	40.0	-	-	39.0	79.0
	%	50.6	-	-	49.4	200.0
Citizens Utilities Co.- Kauai Electric Division	MW	10.0	-	39.9	12.2	62.1
	%	16.1	-	64.3	19.6	100.0
Molokai Electric Company	MW	-	-	-	9.0	9.0
	%	-	-	-	100.0	100.0
HAWAII TOTAL	MW	1,212.9	3.4	155.9	90.0	1,462.2
	%	83.4	0.2	10.8	5.6	100.0

Source: Computations based on information given in Schedule 1 of the 1977 FERC Form 12.

1/ Diesel-generators

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HAWAII

EXISTING GENERATING CAPABILITY

CONTRACT NO. [illegible]
DATE MARCH, 1979

EXHIBIT XII-7