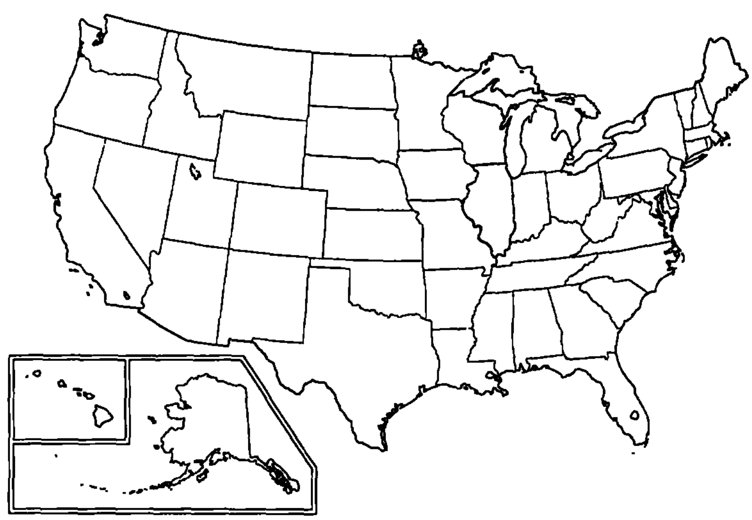
US Army Corps
of Engineers

National Hydroelectric Power Resources Study

Volume XVIII
September 1981

Regional Assessment: Mid-America Interpool Network



IWR 82-H-18

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER Volume XVIII	2. GOVT ACCESSION NO.	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) National Hydroelectric Power Resources Study: Regional Assessment; Mid-America Interpool Network (MAIN)		5. TYPE OF REPORT & PERIOD COVERED Final
		6. PERFORMING ORG. REPORT NUMBER IWR 82-H-18
7. AUTHOR(s) U.S. Army Engineer Division, North Central 536 S. Clark Street Chicago, Illinois 60605		8. CONTRACT OR GRANT NUMBER(s) N/A
9. PERFORMING ORGANIZATION NAME AND ADDRESS Same as No. 7 above.		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
11. CONTROLLING OFFICE NAME AND ADDRESS U.S. Army Engineer Institute for Water Resources Kingman Building Fort Belvoir, VA 22060		12. REPORT DATE September 1981
		13. NUMBER OF PAGES 144
14. MONITORING AGENCY NAME & ADDRESS (if different from Controlling Office) Same as No. 11 above.		15. SECURITY CLASS. (of this report) UNCLASSIFIED
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release; distribution unlimited.

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Hydroelectric power potential; electric power supply and demand; hydroelectric project evaluation; electric power projections

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

This volume briefly describes existing conditions (physical, social, economic) affecting electric supply and demand in the Mid-America Interpool Network. It discusses the existing electric energy system and the role of hydropower therein. Projections of electrical supply and demand through the year 2000 are discussed. The hydropower resources, developed and undeveloped, of the region are evaluated and a regional ranking of specific projects and sites which are recommended to be studied in further detail is presented. The public involvement in the planning process is described.

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SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

U.S. ARMY CORPS OF ENGINEERS

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

REGIONAL REPORT: VOLUME XVIII

MID-AMERICA INTERPOOL NETWORK

SEPTEMBER 1981

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For sale by the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402

PREFACE

The economic success and standard of living in this country have been achieved, in part, at the expense of abundant supplies of low cost, non-renewable, energy sources. In recent years however, diminishing reserves of the preferred non-renewable energy sources, i.e. oil and natural gas, have prompted a national energy policy which emphasizes conservation and the development of new and renewable sources of energy. This report is a direct result of the national energy policy as it focuses on our major existing renewable energy resource, hydroelectric power.

Congress, in the Water Resources Development Act of 1976 (P. L. 94-587), authorized and directed the Secretary of the Army, acting through the Chief of Engineers, to undertake a National Hydroelectric Power Resources Study (NHS). The primary objectives of the NHS were (1) to determine the amount and the feasibility of increasing hydroelectric capacity by development of new sites, by the addition of generation facilities to existing water resources projects, and by increasing the efficiency and reliability of existing hydroelectric power systems; and (2) to recommend to Congress a national hydroelectric power development program.

The final NHS report consists of 23 volumes. Volumes I and II are the Executive Summary and National Reports respectively. Volumes III and IV evaluate the existing and projected electric supply and demand in the United States. Volumes V through XI discuss various generic policy and technical issues associated with hydroelectric power development and operation. Volumes XII and XIII describe the procedures used to develop the data base and include a complete listing of all sites. Volumes XIV through XXII are regional reports defined by Electric Reliability Council (ERC) regions. The index map at the inside back cover defines the ERC regions. Alaska and Hawaii are presented in Volume XXIII.

This volume, number XVIII, describes the hydroelectric power potential in the Mid-American Interpool Network (MAIN) region. A map depicting all sites described in the text is located in the jacket, inside back cover.

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Chapter 1
REGIONAL OBJECTIVES

The overall objectives of the National Hydropower Study are to assess institutional, social, economic and environmental factors affecting development of hydroelectric power and identify the potential for development of the nation's hydropower resources to help meet the short and long term energy demands of the nation.

This Appendix report is intended to be a factual presentation of information developed during the course of the National Hydropower Study. It focuses on the developable hydropower resources within the established boundaries of the Mid-America Interpool Network (MAIN).

The presentation is structured to show the current and projected electrical energy requirements; the physical potential for developing hydropower; the economic, environmental, political, social and institutional constraints to developing the potential; and, the probable uses and impacts associated with developing the acceptable power potential within the region.

There are no unique objectives for developing hydroelectric power potential within the Mid-America Interpool Network (MAIN). In fact, in order to meet current load forecasts, MAIN member systems are planning generating capacity additions which will result in reserve margins in excess of 15% during the 1979-1988 period. These plans include approximately 12,000 MW of nuclear and 6,000 MW of coal fired generating capacity. It is anticipated that the generating capability within MAIN will be adequate to meet forecasted loads, provided that the nuclear generation program can be completed on schedule. The longer range situation is less favorable, since planned generating units face many uncertainties. Restraints by regulations, conflicting environmental goals and financial problems pose threats to an adequate bulk power system. The development of hydropower potential within MAIN would help to alleviate such problems and would contribute to the National objectives of reducing dependency on import of foreign oil and the general enhancement of the welfare and security of the nation.

Chapter 2
EXISTING CONDITIONS

2.1 RELIABILITY COUNCIL PROFILE

Mid-American Interpool Network (MAIN) was organized in November, 1969 as part of the National Electric Reliability Council to promote and improve reliability and adequacy of the bulk power system in the Mid-West. The MAIN region as shown in Figure 2-1 covers the State of Illinois, the eastern halves of Missouri and Wisconsin and the Upper Peninsula of Michigan. Recently, the boundaries of MAIN have been modified to cover the area as shown in Figure 2-2. Such modifications are not reflected in this report since they have recently occurred. The shaded portion shown in Figure 2-2 contains 4 sites which will belong to the Southwest Power Pool (SWPP) reliability council as a result of the boundary modification. These sites are now treated as pertaining to MAIN.

2.2 TOPOGRAPHY

The MAIN Reliability Council Region lies predominately within the Upper Mississippi River Basin and includes small sections of the Ohio River Basin, Missouri River Basin, Lake Superior Basin and the Lake Michigan Basin (Figure 2-2). The major physiographic province is the Central Lowlands with small sections of the Superior Upland, Ozark Plateau, Coastal Plain, and Interior Low Plateaus Provinces being included (Figure 2-3). The present topography in most of the Upper Mississippi River Basin is a result of the Glaciation Period. The glaciers modified the erosional surface developed on the Paleozoic rocks by scouring and filling. A gently rolling terrain, with a progressively less well-developed drainage system to the north, was created. Elevations range from 400 to 2,100 feet above mean sea level. Thousands of lakes characterize the drift-covered Precambrian surface of the headwaters area. The southern part of the basin and the "Driftless Area" (not altered by glaciation) are extensively dissected by streams. Numerous escarpments and bluffs have been created in the relatively flat-lying Paleozoic sedimentary rocks.

2.3 GEOLOGY

Geologically, the MAIN area encompasses features of four different basins, Upper Mississippi River Basin, Lake Superior Basin, Lake Michigan Basin and Missouri River Basin.

Upper Mississippi River Basin

The surficial geology of the Mississippi River above Cairo, Illinois, was greatly affected by Pleistocene glaciation which covered most of the

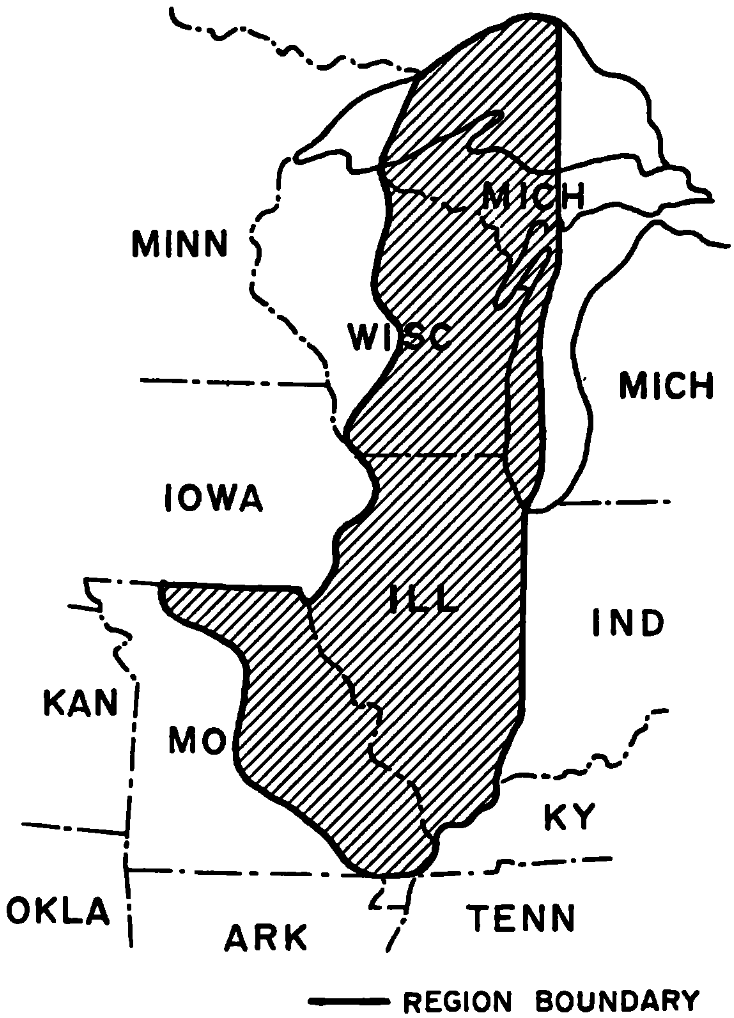

Figure 2-1

MAIN RELIABILITY COUNCIL

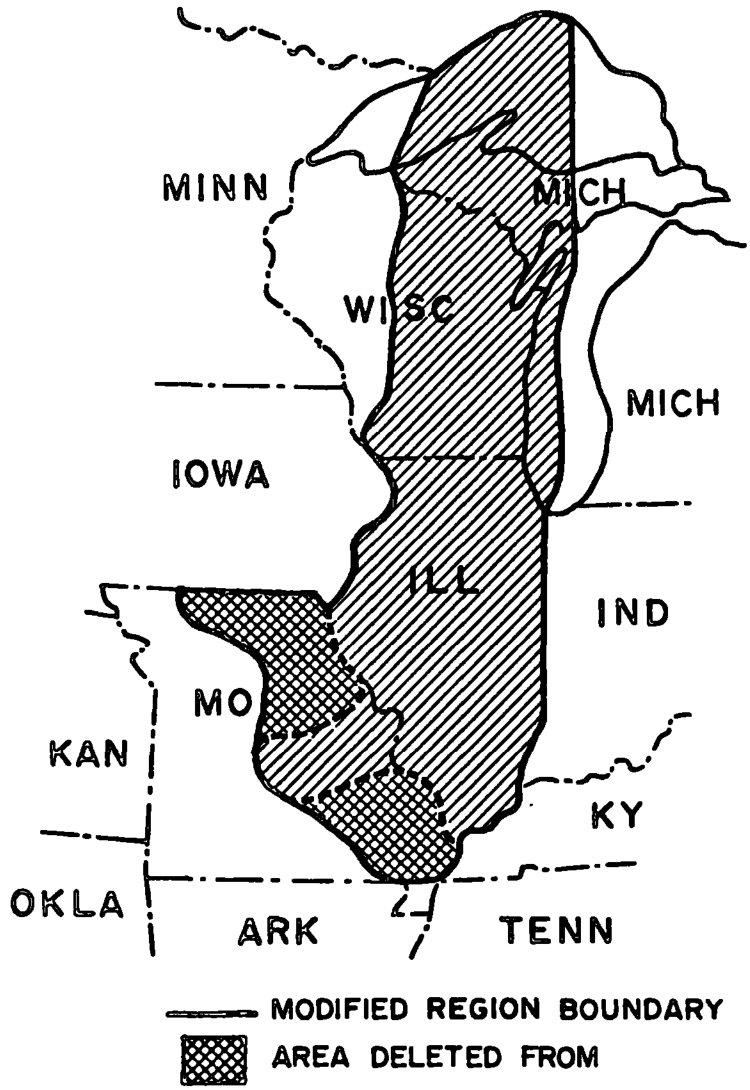

Figure 2-2

MODIFIED MAIN RELIABILITY COUNCIL

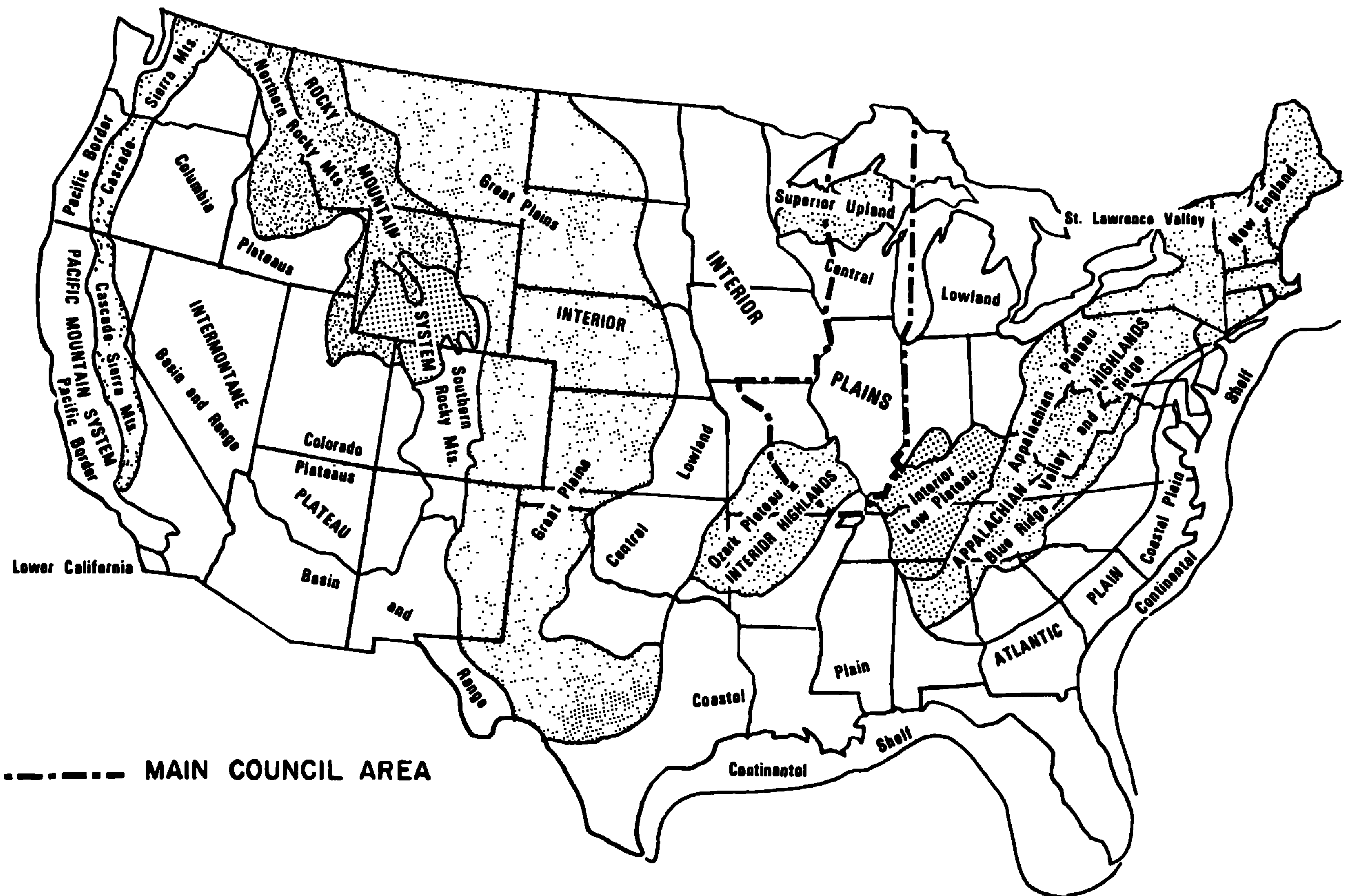

Figure 2–3

PHYSICAL DIVISIONS

Source: "The National Atlas", U.S. Department of Interior, Washington, 1970

Region and resulted in the River being diverted from its channel several times as the ice sheets moved in from east to west and west to east. Consequently, glacial debris buried large parts of the River's former valley, forcing the River to incise a new one in glacial deposits or drift. Such material ranges from a thin veneer to several hundred feet in thichness. Generally, most of the Region's surface is covered with wind blown silt, as much as 300 feet thick in some locations.

Lake Superior Basin

The Lake Superior Basin lies predominately within the Superior Uplands Province. Part of the basin at the eastern end of Michigan's Upper Peninsula is included in the Central Lowland Province. The basin is characterized by its rugged uplands and a rock escarpment bordering parts of the lakeshore. A maximum elevation of 2,031 feet occurs at Eagle Mountain near Grand Marais, Minnesota, but 1,800 to 2,000 feet elevations are common in much of the area.

Lake Michigan Basin

The Lake Michigan basin lies entirely within the eastern lake section of the Central Lowland Province. The basin is characterized by a maturely dissected glaciated terrain. Most of the Lower Peninsula of Michigan and southern Wisconsin has low rolling relief from morainal deposits. To the north, particularly in the Upper Peninsula of Michigan, bedrock crops out and forms more rugged relief. Elevations of a few isolated bedrock peaks in Wisconsin and the Upper Peninsula of Michigan exceed 1,900 feet, but most of the basin's land surface is less than 1,000 feet. A prominent escarpment, extending through Wisconsin's Door Peninsula from Michigan's Garden Peninsula to Lake Winnebago, is formed by the exposed crest of a dolomite formation.

Missouri River Basin

The land that lies north of the Missouri River to the Iowa border is within the Central Lowland Province. This province includes gently rolling plains. Soils in this portion of the province consist of eroded glacial drift and till deposited by continental glaciers with underlying formations of sedimentary deposits of the Pennsylvanian Age. The southern portion of the region has a history of great earthquakes, including three of the greatest earthquakes of known history in 1811-1812.

2.4 HYDROLOGIC CONDITIONS

NORTHEASTERN PORTION OF UPPER MISSISSIPPI RIVER BASIN AND SOUTHWESTERN PORTION OF GREAT LAKES BASIN

Climate

General—A number of natural climate controls affect the region. One of the most important is solar radiation, which supplies energy for the hydrologic cycle. The movement of large masses of air from various regions into these basins is another control. Dry, cold air from polar regions covers these basins at times. A large percentage of the total annual precipitation occurs at other times when warm, moist air from the Gulf of Mexico dominates basin weather. The climate of the region is of the continental type, which varies somewhat from the northern to the southern extremities.

Precipitation

General - The main features of the precipitation patterns in the region include:

(a) In general, annual average precipitation exceeds loss of soil moisture through evapotranspiration.

(b) There is more precipitation in the spring and summer months, on the average, than in the fall and winter months. In the southern extremity, there is less seasonal variation than in the middle and northern parts of the region.

(c) There are comparatively large fluctuations of precipitation from year to year, and from place to place within a given year.

Specific - Precipitation on the Upper Peninsula of Michigan is a result of the intermingling of humid tropical air masses from the United States Gulf region and dry continental arctic air masses from Canada. The meeting of these masses creates precipitation that averages between 28 and 36 inches annually. Summer rainfall is usually of lower intensity, with occasional high intensity thunderstorms.

The humid, continental climate of Wisconsin is influenced by storms that move eastward along the northern border of the United States, and northeastward from the southwest to the Great Lakes. The average annual precipitation ranges from 29 to 33 inches. Approximately 55 percent of the precipitation occurs from May through September. Rainfall is evenly distributed. During the summer months, thunderstorms occur frequently and are occasionally violent, often accompanied by damaging hail and high winds. The number of thunderstorms per year varies from about 30 in the north to over 40 in the south; tornadoes occur occasionally.

Illinois and Missouri experience a humid continental climate, which varies somewhat from the northern to southern extremities. Average annual precipitation ranges from approximately 33 inches in the north to 41 inches south of the Missouri River.

Annual average snowfall amounts vary in the two watersheds from a high of over 100 inches in the Upper Peninsula of Michigan and the Upper Wisconsin highlands to a low of 8 inches at the southern tip of Illinois. The percentage of annual precipitation attributed to snow, sleet, and glaze ranges from about 30 percent in the extreme northeast to about 4 percent in the extreme southern part. In the northern part of the region the average number of days with snow on the ground (1 inch or more) is over 120 and in the southern part the average is about 20.

Evaporation and Evapotranspiration

Evaporation ranges from about 29 inches in the north to about 49 inches in the south.

Evapotranspiration ranges from about 24 inches in the north to about 30 inches in the south.

Temperature

General - January has the lowest temperature and July has the highest temperature in the basin. The average annual temperature for the region ranges from about 40°F in the northern extremity to about 59°F in the extreme south.

The daily temperature cycle is characteristic of a continental type. The daily cycle includes the following:

(a) Maximum temperature occurs after local noon, and minimums near sunrise.

(b) Relative humidity varies inversely with temperature.

(c) Wind increases and veers clockwise by day and decreases and veers counterclockwise by night.

(d) Cloudiness and precipitation over a land surface increase by day and decrease by night; over water the reverse is true, but to a lesser extent.

(e) Evaporation is markedly greater by day.

(f) Condensation is much greater by night.

Illinois and Missouri experience a humid continental climate. The average monthly temperature varies in northern Illinois from a high of 76°F in July to a low of 25°F in January. In southern Illinois the average monthly temperature for July is 80°F and the low is about 35°F in January.

Wind

Regional surface wind patterns for January, April, July and October are described as follows:

(a) January - Winds are most frequently from the northwest with a mean speed of about 11 miles per hour.

(b) April - Winds in basin northwest of a line from Chicago, Illinois, to St. Louis, Missouri, are most frequently from the northwest and the mean speed increases to about 14 miles per hour. South of this line the winds are from the south with a mean speed of about 13 miles per hour.

(c) July - Winds over the entire basin are predominately southerly and the mean speed is about 8 miles per hour.

(d) October - Winds are most frequently from the south and the mean speed is about 10 miles per hour.

Individual storms, frontal systems, and air masses frequently cause large variations from these patterns. Local topography causes local deviations.

Runoff

Average annual runoff for the region varies from about 15 inches per year over the Upper Peninsula of Michigan to about 10 inches in central Wisconsin to 8 inches along the Illinois state line to about 10 inches in central Illinois and northern Missouri and in excess of 12 inches in southern Illinois.

2.5 ECONOMICS OF THE AREA

General*

Table 2-1 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. (Ref. 2-2)

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 sub-region had the largest population of the three sub-regions in MAIN, 9.4 million in 1970, over 50 percent of the MAIN region total. The Illinois-Missouri and Wisconsin-Upper Michigan System sub-regions each contained 29 and 20 percent of the total region population, respectively.

Total earnings originating in the MAIN region increased 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

*Source: Ref. 2-1

Table 2-1

MAIN ECONOMIC INDICATORS

Sector Earnings[1/] (Million$)	MAIN	Commonwealth Edison	Wisconsin Upper Michigan System	Illinois-Missouri
Agriculture	1,473	393	382	699
Mining	318	72	57	189
Construction	3,596	2,053	617	927
Manufacturing	19,234	11,115	3,802	4,318
Transportation Utilities	4,057	2,367	591	1,099
Trade	9,627	5,655	1,599	2,373
Finance	2,752	1,696	426	630
Services	7,874	4,658	1,292	1,897
Government	7,623	3,748	1,467	2,416
Total Earnings (Million$)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
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 area: 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, properties income and other labor income) property income and transfer payments, less personal contributions for social insurance.

1/ Constant 1967 dollars.

Sources: Ref. 2-1

market. The major portions of MAIN earnings originated in the Commonwealth Edison sub-region. The Illinois-Missouri and Wisconsin-Upper Michigan System sub-regions, 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 MAIN region industries have been shrinking shares of the corresponding national sector totals during the period between 1950 and 1970.

The 1970 Commonwealth Edison sub-region sectoral earnings exceeds corresponding sectoral earnings in the other sub-regions, except in agriculture and mining. The 1970 agriculture and mining earnings originating in the Illinois-Missouri sub-region exceed the earnings of the other two sub-regions. All three of the sub-regions are dependent upon manufacturing, trade and service industries for a major portion of the total earnings. State, local and Federal government sectors also provide a significant amount of income in each of the sub-regions.

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 sub-region was 19 percent higher than the national average, and 10 percent higher than MAIN regional averages. The Illinois-Missouri and Wisconsin-Upper Michigan System sub-regions 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 sub-region.

Upper Peninsula of Michigan

The central portion of Michigan's Upper Peninsula has severe soil and climatic limitations which results in very limited agricultural productivity. This region has the fewest number of farms and least amount of land in farming in the entire Great Lakes Basin. Most of the farm sales from the MAIN area are from livestock.

Support of the area economy is bolstered by mining, forestry, and recreation. Overall, this area is considered only a marginal part of the State of Michigan's economy. Iron mining dominates the economy in the western areas. This industry has replaced the copper industry that started and grew in the middle and late 1800's. Since the copper resources were almost completely exploited, industry efforts had to turn in other directions. Today, mineral operations are utilizing the granite, basalt, iron, marble, dolomite, and what is left of the copper resources.

Forestry is locally important. Large tracts of land are owned by lumbering concerns that plant and manage these resources. Some mills are capable of producing almost a million board feet of lumber annually. The availability of this wood material has resulted in the development of numerous wood product associated businesses.

The recreation and tourism industry is very important to this area. Among the advantages and attractions of the area are a unique history of mining, scenic beauty, numerous streams and lakes for boating and fishing, national and state forests, steep hills for skiing, numerous campgrounds, and large wilderness areas for hunting.

There is little question that this region of MAIN is economically depressed. Even in the summer months with increased construction activity and tourism, the unemployment rate is high, and has been ten percent or more in recent years.

One direct result of the tight labor market in this area is the outmigration of younger people. This further stagnates the local economy as it results in a disproportionate number of the very old and the very young. These groups place a proportionately greater demand on community service functions.

Thus, there is greater economic pressure on the existing labor force, not only because large numbers are unable to find work, but also because expenditure requirements for public services are greater relative to non-depressed areas. The end result is either high taxes or depreciation in the quality of public facilities and services.

Wisconsin River Basin*

The Wisconsin River Basin is predominantly rural with a few medium-sized metropolitan areas within the basin. Available land and water resources coupled with a wide variety of economic development provide an excellent base for future growth of the economy of the basin.

Agricultural activities are confined mainly to the central and southern portions of the basin. The soil and climate are especially suited to dairy farming, which accounts for over 50 percent of the farming activity in the area. About 59,000 acres of farmland in the basin were irrigated in 1964. This represented about 71 percent of the total irrigated land in the State of Wisconsin. The chief field crop is hay. Other field crops are forage, corn, oats, wheat, rye and soybeans.

*Source: Ref. 2-3

Pulp and paper making is the largest industry in the basin. Large pulp and paper mills are found in twelve cities and towns along the Wisconsin River between Rhinelander and Nekoosa. Various enterprises associated with dairying such as creameries, condenseries, and cheese plants are found throughout the basin.

The forest products industry, supported by the region's forest resources, is an important part of the basin's economy. The forests are found to a large extent in the northern half of the basin. Although much of the timber supply has now been exhausted, the forest stands are still quite substantial. Federal, State, county, and industrial agencies and organizations have been engaged for some years in the improvement of stands and in reforestation. The cut timber is mainly used in the pulpwood and paper industry and in saw log production. Because of the depleted supply of softwoods, today's timber harvest is about 75 percent hardwood.

The recreation industry in the Wisconsin River Valley is well developed and is a major source of income.

Three areas in the basin, Adams County, Vernon County, and the Indian reservations in Vilas, Forest, and Menominee Counties, have been classified as depressed areas by the Economic Development Administration, Department of Commerce, formerly "Area Redevelopment Administration." These areas qualify for Federal assistance because of persistent unemployment, population loss, low income and Indian reservation land.

Illinois*

Illinois ranks first nationally in the maufacturing of non-electrical machinery and of fabricated metals. It is second in food processing and in the printing and publishing industries, and third in the manufacturing of electrical machinery. Illinois is a major automotive center as well, with more than 550,000 persons employed in the assembly and use of motor vehicles. Some 250 industrial parks are scattered throughout the state, the greatest concentration being in the Chicago metropolitan area.

Among Illinois' natural resources are approximately 40 coal seams with the underground mines in the south having the highest production per man-day in the country. The most important natural resource is the land itself. Some 124,000 large and small farms cover more than 75% of the state's area. For many years, Illinois has been the nation's major soybean producer, and from year to year it trades places with Iowa for first-rank in corn production.

It is second in both pork and beef productions, while other grains, dairy products, and meat animals hold high positions. In spite of a growing national trend toward large corporate-farm operations, family-owned farms account for about 99% of farms and 97% of the farm acreage in Illinois.

Illinois ranks second only to Texas in number of independent banks, attributable to the state's prohibition against branch banking. Illinois

*Source: Ref. 2-4

is a major insurance center, headquartering the two largest automobile insurers in the world. Chicago is the seat of the seventh district of the Federal Reserve Bank as well as of the Midwest Stock Exchange and the Chicago Board of Trade. The Board of Trade is the nation's largest commodity market, dealing in contracts for grains, soybeans and their products, silver, plywood and lumber, livestock and dairy products.

Illinois is recognized as the transportation center of the United States. Chicago is the country's rail capital and the state's more than 23,000 miles of track rank it second highest in the nation. Water transportation is extensive with major routes on the Great Lakes, the Mississippi River and Illinois Rivers.

Missouri*

Missouri has become the commercial and industrial leader among all its adjacent states, except Illinois. In some types of manufacture, particularly in the production of aerospace and transportation equipment, including automobile assembly, Missouri ranks second in the nation. Kansas City and St. Louis have always been important trading and commercial centers for large regions reaching into neighboring states. They rank among the foremost grain and cattle markets of the nation.

The state's variety of resources includes lead and iron ore, limestone, timber, animal hides, vegetable fibres, hydroelectric power, natural transportation routes, and harbors in abundance. Its chief sources of income are, in order of importance, manufacturing, agriculture, and tourism.

Manufacturing is led by the production of aerospace and transportation equipment, followed by the processing of food and kindred products and the production of chemicals.

Mineral-rich Missouri leads the nation in lead production, and continuing new discoveries of lead, as well as iron ores, assure this position.

Missouri ranks among the top ten states in banking and financial institutions of all kinds. Federal Reserve Banks are located in both Kansas City and St. Louis and the Internal Revenue Service offices in Kansas City serve much of the Middle West.

The major flows of waterborne traffic within the state are east-west along the Missouri Valley and southward along the Mississippi. The Mississippi and Missouri Rivers, providing 1,000 miles of navigable waterways within the state, connect waterborne traffic with New Orleans.

2.6 MAJOR ENERGY USERS

Energy consumption as percent of total for the consumer categories (residential, commercial, and industrial) for utilities in each of the three sub-regions is given in Table 2-2. Annual growth rates of energy

*Source: Ref. 2-5

Table 2-2

ENERGY CONSUPTION BY CONSUMER CATEGORIES

(Percent of Total)

Representative Utilities	Residen-tial	Commer-cial	Indus-trial	Total
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	30.3	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.

consumption by the consumer categories for the period 1973-1977 are given in Table 2-3.

In general, annual growth rates for total energy consumption in 1974 for the three sub-regions 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 sub-regions experienced a substantial decrease in energy growth in 1974 and 1975 In 1974 and 1976 decreases in residential growth rates were experienced in Commonwealth Edison and the Illinois-Missouri sub-regions.

2.7 FUTURE DEVELOPMENT*

Table 2-4 summarizes the significant demographic and economic projections for MAIN. Tables 2-5 through 2-7 summarize the projections for the three sub-regions as approximated by the selected BEA economic areas. The projections are based on the 1972 OBERS projections.

MAIN had about 9.2 percent of the total U.S. population and 10.1 percent of the U.S. total personal income in 1970. The shares of the population and income in MAIN are expected to decrease through the period 1970 to 2000. The distribution of the population within MAIN during 1970 and the projection for 2000 are as follows:

Sub-Region	Percent of MAIN Population	
	1970	2000
Commonwealth Edison Sub-Region	50.3	51.9
Illinois-Missouri Sub-Region	29.3	28.4
Wisconsin-Upper Michigan Sub-Region	20.4	19.7

The population growth of the area is projected to slow from the historical average annual growth rate of 1.3 percent between 1950 to 1970 to an annual growth rate of 0.6 percent between 1980 and 2000, slightly lower than the national average. Population growth in the sub-regions is projected to closely follow the overall trend in MAIN.

Earnings and total personal incomes in constant dollars are projected to grow at 3.2 and 3.3%, respectively, slightly lower than the national average. No large disparity among the sub-regions in growth of total earnings is expected. Historically, manufacturing and trade have had the largest earnings in MAIN. But by the year 2000, earnings in services and government sectors are expected to exceed trade earnings.

*Source: Ref. 2-6

Table 2-3

ANNUAL GROWTH RATES OF ENERGY CONSUMPTION BY CONSUMER CATEGORIES*

(Percentage)

Representative Utilities or Power Groups	Residential 1973	1974	1975	1976	1977	Commercial 1973	1974	1975	1976	1977	Industrial 1973	1974	1975	1976	1977	Total 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 Bublic Service Company	7.7	2.3	11.6	1.4	8.9	7.5 2/	0.0	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	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	0.0	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-industrial combined shown as industrial.
4/ Includes both industrial and commercial.

* Source: Ref 2-1.

Table 2-4

PROJECTED POPULATION INCOME AND MAJOR SECTOR EARNINGS (OBERS)

MAIN

POWER SERVICE AREA:
MID AMERICA
INTERPOOL NETWORK (MAIN)

SERVICE AREA APPROXIMATED BY BEA AREAS:
57 58 77 78 79 82 83 84 85 86
112 113 114

SECTOR EARNINGS (MILLION $)	******************** YEAR	********************		
	1980	1985	1990	2000
AGRICULTURE	1739.	1792.	1848.	2053.
MINING	355.	376.	397.	458.
CONSTRUCTION	5439.	6262.	7210.	9617.
MANUFACTURING	26558.	30194.	34340.	44941.
TRANSPO UTILITIES	5742.	6605.	7620.	10287.
TRADE	13418.	15293.	17433.	23239.
FINANCE	4503.	5424.	6535.	9462.
SERVICES	13822.	17056.	21050.	31703.
GOVERNMENT	11638	14069.	17010.	24705.
TOTAL EARNINGS (MILLION $)	83219.	97157.	113450.	156470.
TOTAL PERSONAL INCOME (MILLION $)	104487.	122742.	144215.	200691.
TOTAL POPULATION (THOUSANDS)	20182.	20919.	21686.	22933.
PER CAPITA INCOME ($)	5177.	5867.	6650.	8751.
PER CAPITA INCOME RELATIVE TO U. S.	1.08	1.08	1.08	1.07

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.

EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS (Ref. 2-6).

Table 2-5

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)

CECO

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
COMMONWEALTH EDISON

SERVICE AREA APPROXIMATED BY BEA AREAS:
77 79 82

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	492.	504.	516.	569.
MINING	77.	79.	82.	92.
CONSTRUCTION	3147.	3617.	4157.	5533.
MANUFACTURING	15249.	17307.	19632.	25652.
TRANSPO UTILITIES	3343.	3846.	4424.	5953.
TRADE	7764.	8860.	10111.	13519.
FINANCE	2697.	3241.	3894.	5636.
SERVICES	8134.	10029.	12365.	18597.
GOVERNMENT	5789.	7020.	8512.	12443.
TOTAL EARNINGS (MILLION $)	46695.	54536.	63695.	87995.
TOTAL PERSONAL INCOME (MILLION $)	57586.	67738.	79682.	111215.
TOTAL POPULATION (THOUSANDS)	10258.	10683.	11127.	11892.
PER CAPITA INCOME ($)	5614.	6341.	7161.	9352.
PER CAPITA INCOME RELATIVE TO U. S.	1.17	1.17	1.16	1.15

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS (REF. 2-6).

Table 2-6

PROJECTED POPULATION,.INCOME AND MAJOR SECTOR EARNINGS (OBERS)

ILL-MO

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
ILLINOIS-MISSOURI

SERVICE AREA APPROXIMATED BY BEA AREAS:
57 58 78 112 113 114

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	837.	866.	897.	1001.
MINING	223.	240.	258.	304.
CONSTRUCTION	1383.	1597.	1845.	2462.
MANUFACTURING	6162.	7089.	8162.	10807.
TRANSPO UTILITIES	1523.	1750.	2011.	2712.
TRADE	3362.	3832.	4370.	5800.
FINANCE	1066.	1291.	1564.	2264.
SERVICES	3366.	4168.	5161.	7790.
GOVERNMENT	3568.	4293.	5167.	7421.
TOTAL EARNINGS (MILLION $)	21492.	25151.	29438.	40564.
TOTAL PERSONAL INCOME (MILLION $)	27708.	32580.	38317.	53173.
TOTAL POPULATION (THOUSANDS)	5860.	6049.	6245.	6524.
PER CAPITA INCOME ($)	4728.	5386.	6135.	8150.
PER CAPITA INCOME RELATIVE TO U. S.	.99	.99	1.00	1.00

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS (Ref. 2-6).

Table 2-7

PROJECTED POPULATION, INCOME AND MAJOR SECTOR EARNINGS (OBERS)

WUMS

POWER SERVICE AREA:
MID AMERICA INTERPOOL NETWORK
WISCONSIN-UPPER MICHIGAN SYSTEM

SERVICE AREA APPROXIMATED BY BEA AREAS:
83 84 85 86

SECTOR EARNINGS (MILLION $)	1980	1985	1990	2000
AGRICULTURE	409.	422.	435.	483.
MINING	55.	56.	57.	62.
CONSTRUCTION	909.	1048.	1208.	1621.
MANUFACTURING	5147.	5803.	6546.	8482.
TRANSPO UTILITIES	876.	1010.	1185.	1623.
TRADE	2292.	2600.	2952.	3919.
FINANCE	740.	892.	1077.	1562.
SERVICES	2322.	2859.	3524.	5316.
GOVERNMENT	2281.	2756.	3331.	4841.
TOTAL EARNINGS (MILLION $)	15032.	17470.	20317.	27911.
TOTAL PERSONAL INCOME (MILLION $)	19193.	22424.	26216.	36304.
TOTAL POPULATION (THOUSANDS)	4065.	4187.	4314.	4517.
PER CAPITA INCOME ($)	4722.	5356.	6076.	6038.
PER CAPITA INCOME RALATIVE TO U. S.	.99	.99	.99	.98

NOTE: SUM OF SECTOR EARNINGS MAY NOT EQUAL THE TOTAL BECAUSE OF DISCREPANCIES IN OBERS DATA.
EARNINGS AND INCOME IN CONSTANT 1967 DOLLARS (Ref. 2-6).

Per capita income in MAIN has historically been higher than the national average and is expected to remain above national level through the year 2000. However, the disparity between MAIN and national averages of per capita income is expected to decrease.

The Commonwealth Edison sub-region is projected to experience higher per capita income than the Illinois-Missouri and Wisconsin-Upper Michigan sub-regions. However, the growth rate of per capita income between 1985 and 2000 in the Commonwealth Edison sub-region is expected to be only 2.6%, while growths of per capita income in the Illinois-Missouri and Wisconsin-Upper Michigan sub-regions are expected to be slightly higher at 2.8 and 2.7%, respectively.

REFERENCES

2-1. Harza Engineering Company, "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study, Phase I - 1978 Electric Power Damand and Supply", Institute for Water Resources, Fort Belvoir, Virginia, April 1979.

2-2. 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 1974.

2-3. Upper Mississippi River Comprehensive Basin Study Coordinating Committee, "Upper Mississippi River Comprehensive Basin Study, Appendix P, Economic Base Study and Projections", 1970.

2-4. Encyclopedia Brittanica, Macropadeia Volume 9, Chicago, 1974.

2-5. Encyclopedia Brittanica, Macropaedia Volume 12, Chicago, 1974.

2-6. Harza Engineering Company, "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study, Phase II - Future Electric Power Damand and Supply", Institute for Water Resources, Fort Belvoir, Virginia, March 1980.

Chapter 3

EXISTING ENERGY SYSTEMS

3.1 EXISTING ENERGY SYSTEMS[1/]

MAIN had a 1978 generating capability of 41,600 MW. The type of sources for this capability are shown in Table 3-1. The table also shows the 1988 projected capability. These figures were compiled by the National Electric Reliability Council. A complete listing of all MAIN facilities is in Appendix A. Generating capability by types of plants for MAIN and the three sub-regions is shown in Table 3-2. Coal-fired steam is the bulk source of generation, supplying about 67% of MAIN's total capability. It represents the highest percent of the total sub-region capability in Illinois-Missouri at 86.0% with the Wisconsin-Upper Michigan and Commonwealth Edison sub-regions 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 sub-regions. Hydropower contributes an additional 3.2% in the Wisconsin-Upper Michigan sub-region. The Illinois-Missouri sub-region has about 4% hydro capability with an additional 3.4% of combustion turbine to supply peaking power. Ownerships of generation sources in MAIN are shown in Table 3-3.

Table 3-1

GENERATING CAPABILITY BY TYPE (MW)

	1978	%	1988*	%
Nuclear	6,500	15.6	18.600	30.3
Coal-Fired	27,800	66.9	33.500	54.7
Oil	6,500	15.6	8.400	13.7
Hydro	0,800	1.9	0.800	1.3
	41.600	100.0	61.300	100.0

*Projected

1/ Source: Ref. 3-1

Table 3–2

MAIN GENERATING CAPABILITY

(Percent of Total)

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

SOURCE: MAIN, "1978 Reply to Appendix A-2 of FPC Order 383-4, Docket R-362", 1 April 1978.

Table 3-3

OWNERSHIP OF GENERATION SOURCES[1/]

	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				
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	-	255	7,463
%	97.0	-	3.0	100.0

1/ Based on capability as of 1 January 1978.
SOURCE: MAIN, "1978 Reply to Appendix A-2 of FPC Order No. 383-4, Docket R-362," April 1, 1978.

3.2 MAIN'S MEMBERSHIP

MAIN's regular membership is composed of investor-owned, rural cooperative and municipal power suppliers. To expedite operation of the council, the members are arranged in geographical groups. The groups and related members are as follows:

Groups	Members
Commonwealth Edison Group (CECO)	Commonwealth Edison Company
Illinois Group (ILMO)	Central Illinois Light Company Central Illinois Public Service Company Illinois Power Company City Waters, Light & Power Springfield Southern Illinois Power Cooperative
Missouri Group (ILMO)	Union Electric Company
Wisconsin-Upper Michigan System Group (WUMS)	Madison Gas and Electric Company Wisconsin Electirc Power Company System Wisconsin Power and Light Company Wisconsin Public Service Corporation Upper Peninsula Power Company

Municipal and other small electric systems operating in the MAIN region are associate members. They are not eligible for membership because their operations do not significantly affect the reliability of the region. The associates members are as follows:

Groups	Associate Members
Illinois Group	Association of Illinois Electric Cooperative Western Illinois Power Cooperative, Inc. Soyland Power Cooperative
Wisconsin-Upper Michigan System Group	Municipal Electric Utility of Michigan

3.3 ROLE OF EXISTING HYDROPOWER

Hydropower, including conventional hydroelectric and pumped storage plants, represents only 1.9% of the MAIN region generating capability, as compared to about 14% of the 1977 national capability. As shown in Table 3-4, 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 Lock and Dam 19 (119 MW), on the Mississippi River between Illinois and Iowa, and Bagnell Dam (172 MW) on the Osage River in Missouri. In Wisconsin, Wisconsin and Fox Rivers are developed extensively for hydropower by a series of plants which recover the useful energy available. The same is true of the Menominee River in the Upper Peninsula of Michigan. There are other small hydropower plants scattered throughout Wisconsin and the Upper Peninsula of 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. There are several hydromechanical plants which utilize the flows directly and do not generate electricity, but are part of the existing hydropower base. The few hydropower sites in the Commonwealth Edison sub-region are of a small size. This is due to the region's lack of streams with large flows and heads.

Some hydroelectric plants are owned 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 are 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 the Ludington, Michigan Pumped Storage Plant 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 Plant is operated primarily as reserve; the Commonwealth Edison portion of Ludington is used actively to improve thermal economy.

3.4 HYDROPOWER POTENTIAL

The Federal Power Commission (FPC) evaluated the hydropower potential of the MAIN region in their 1976 study. This study differs from the result of the NHS study in that the FPC study identified significant potential at undeveloped sites while the NHS showed no potential at undeveloped sites. Table 3-5 summarized the results of the FPC study. The undeveloped sites are restricted to those with potential installed capacities greater than 5 MW. Existing dams with a potential installed capacity of less than 5 MW make up the bulk of inventory, with potential installed capacity amounting to 980 MW. Average annual generation associated with all of the potential sites at existing dams in MAIN amounts to 4,298 GWh.

Table 3-4

OWNERSHIP OF HYDRO[1/]

	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.

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

1/ Based on capability as of 1 January 1978.

Table 3-5

MAIN UNDEVELOPED HYDROPOWER POTENTIAL*

Potential at Undeveloped sites (Greater than 5 MW)	Potential Installed Capacity (MW)	Average Annual Energy (1000 MWh)
Commonwealth Edison Subregion	105	531
Illinois-Missouri Sub-region	346	1,024
Wisconsin-Upper Michigan Sub-region	200	791
MAIN Total	651	2,346
Potential at Existing Dams		
MAIN	1,295	4,298
Total Potential	1,936	6,644

Note: These results are based on the 1976 FPC report and not the results of the National Hydropower Study.

*Source: Ref. 3-3

As can be seen from the previous table, potential hydroelectric sites in MAIN are relatively limited in size and number. According to the FERC analysis total potential at undeveloped sites is 651 MW and 1,295 MW at existing dams; the average annual energy production is 6,644 GWh. In 1978, the installed hydropower capacity was about 500 MW in MAIN, and the energy production was 2,300 GWh.

Although potential hydroelectric sites protected by the Wild and Scenic River Act are not included in Table 3-5, segments of the Gasconade and Wisconsin Rivers have been designated for study under Section 5(a) of the Wild and Scenic Rivers Act (as of January 1, 1976) are included. The potential capacities of these rivers may be restricted from development.

Total undeveloped capacity in the Commonwealth Edison sub-region is limited. Only 105 MW of potential capacity at undeveloped sites with an annual energy of 531 GWh exists in the Commonwealth Edison sub-region.

In general, the available undeveloped sites for conventional hydropower are limited and are too small for economical development at the present time. According to FERC the total potential at undeveloped hydropower sites was estimated to be 651 MW in MAIN, corresponding to an average annual generation of 2,346 GWh.

3.5 AVAILABILITY OF FUELS*

About 11% of the coal reserves in the contiguous United States are in MAIN. Most of this coal is unevenly distributed throughout the region, with major deposits in southern Illinois and a small amount in Missouri. In general, all of the MAIN coal has high sulfur content. Coal with lower sulfur content is shipped from Kentucky, Wyoming, Montana, and the Dakotas. The Illinois-Missouri and Wisconsin-Upper Michigan sub-regions depend heavily on coal because of their proximity to these coal-producing regions. The Commonwealth Edison sub-region also depends on coal for a major portion of its generation, but has a large amount of nuclear generation existing and committed.

The major problem with MAIN coal is that it is high in sulfur, with combustion producing sulfur dioxide levels in excess of allowable limits. With present technology, the sulfur may be removed before combustion or separated in the stack after burning, but these processes are costly in terms of energy and equipment. Low sulfur western coal may be burned, but it has low BTU content. Also, use of western low sulfur coal rather than midwest coal may have severe impacts on the social and economic structure of coal-producing areas in Illinois and Missouri. Currently, coal from the two sources are mixed. Trends are for use of local coal accompanied by suitable flue gas cleaning equipment.

Breakeven cost analysis between coal and nuclear energy indicates nuclear energy generation might be more economical than base load coal generation (Refs: 3-4, 3-5, 3-6, and 3-7). However, uncertainties exist concerning the future of nuclear fuel sources, environmental and nuclear waste disposal restrictions may lead to coal plant additions in future years. New oil-fired plants are not likely to be considered as viable for either peaking or base load plants, because of the uncertainty associated with fuel supplies as well as rapidly increasing prices. Government regulations discourage the addition of gas-fired plants. Current trends are that the portion of system capability associated with oil-fired and gas-fired generation will diminish as existing plants are converted to coal or retired.

3.6 RESERVE MARGIN AND SYSTEM RELIABILTY*

For a number of years, MAIN used a method referred to as POPM (probability of positive margin) to determine generation reserve requirements. POPM was designed to examine only the system peak condition, taking into account the

*Source: Ref. 3-3

probability of the annual peak demand deviating from the forecast value. Now MAIN is using the loss of load probability (LOLP) method, which combines the generation capacity outage probability with the expected daily peak demand to give an expected risk of load exceeding capacity. LOLP also can consider the deviation of daily peak demand from forecast. As a result of this new procedure, recent studies have indicated that a minimum generating reserve of 15% would be adequate for MAIN as a whole.

To enhance its system reliability, MAIN has two Interregional Reliability Coordination Agreements, a two-party agreement with MARCA and a three-party agreement with ECAR and TVA. These agreements provide for periodic review of the adequacy and reliability of the interregional systems. Coordination with the Southwest Power Pool (SWPP) is accomplished informally through the MAIN utilities that are contiguous to SWPP and have membership in both regions. Transfer capabilities for 1988, as projected by the NERC regions, are shown in Table 3-6.

For the three utilities representative of MAIN, the average annual base load varies between 59 and 61%, and the peak load varies between 12 and 19% of the total annual demand. The portions of the load considered as base, intermediate or peak are the basis for deriving the generation mix.

Table 3-6

RESERVE MARGINS

(Percent of Peak Demand)

	1985 (%)	1990 (%)	1995 (%)	2000 (%)
Commonwealth Edison Sub-region	23	17	17	17
Illinois-Missouri Sub-region	20	20	20	20
Wisconsin-Upper Michigan Sub-region	17	17	17	17

3.7 GENERATION MIX*

This section presents future expansion plans. An estimate of suggested generation mix for base, intermediate, and peaking capacities is evaluated for MAIN and each of its three sub-regions. These evaluations are based on existing and planned generation facilities as reported by the utilities, characteristics of electric loads, on an analysis of regional resource availability, economic parameters, federal and state regulations, and other pertinent regional factors. To reflect the uncertainties and unforeseeable

*Source: Ref. 3-3

factors which can affect future generation mixes, a range of future installed capacity is defined for each major generation source. The projected future capabilities are based on the "median" demand, and the reserve margins discussed in Chapter 4 (Tables 4-2 to 4-5).

3.8 OPERATING PROCEDURES*

General

Monitoring of the day-to-day operating reserves is accomplished through the functioning of the MAIN Coordination Center, Lombard, Illinois. Each morning the MAIN members report their planned operating reserves for the day, and at least once a day the actual reserves are recorded. On days when the capacity situation is tight, the actual operating reserve is recorded more frequently. By broadcasting this information on a teletype system, MAIN members are kept informed of the status of the power supply condition in the region.

The operation of the transmission system is also monitored by the Coordination Center. If unusual conditions develop, due to line outages, the computer at the Center can be used to analyze the situation and provide guidance for the MAIN members to avoid overstressing the network.

Under extreme emergencies, when there is a serious deficiency of operating reserve in the region, the members of MAIN are expected to follow a standard operating procedure to prevent cascading outages and a widespread blackout.

Definition of Operating Reserve

Operating Reserve is that reserve required to provide for (a) regulation to cover minute-to-minute variations in load, (b) local forecasting errors, (c) loss of equipment, and (d) local area protection. Operating Reserve is the sum of Spinning Reserve plus Non-Spinning Reserve, both of which components are defined below:

1. Spinning Reserve is that component of Operating Reserve which is connected to the bus (bus-insulated bar used as an electrical conductor at a circuit junction) and which can be fully applied within ten minutes.

2. Non-Spinning Reserve is that component of Operating Reserve which is not connected to the bus, but which is capable of being made effective in ten minutes or less and which can be utilized for a period of at least three hours.

*MAIN, Regional Reliability Council Coordinated Bulk Power Supply Program, April 1, 1979

Minimum Operating Reserve of Generating Capacity

Operating Reserve is required in a well-operated system to help provide a safeguard against the occurrences of an uncontrolled area-wide interruption. MAIN has prepared a Guide (Appendix 5 of the referenced April 1, 1979 report) which defines Operating Reserve and establishes the criteria for the minimum level of such reserve for MAIN as a whole and for the distribution of such reserve among the subgroups of MAIN.

Reserve Requirements

The minimum Operating Reserve required in the MAIN Coordination Area is equal to 1.5 times the winter normal capacity of the largest generating unit in commercial service. This requirement recognizes that if the largest unit in MAIN is lost suddenly, the system still must provide an adequate level of operating reserve in MAIN to protect against another contingency of limited magnitude until steps can be taken to restore the level of Operating Reserve to normal. It is also recognized that emergency assistance from systems in contiguous regions (e.g., ECAR, MARCA, SWPP, and SERC) is available in most instances.

The minimum level of Spinning Reserve to be carried in the MAIN Coordination Area is equal to 50 percent of the minimum Operating Reserve requirement. This recognizes that systems in MAIN have installed fast-start peaking capacity and that the use of such capacity as a component of Operating Reserve is practical and consistent with good operating practices.

Distribution of Operating Reserve

The Operating Reserve of MAIN is distributed among the three subgroups of MAIN (e.g., CECO, IL-MO, and WUMS) in proportion to the winter normal rating of the largest generating unit in commercial service in each subgroup to the sum of the ratings of the largest generating units in commercial service in the three subgroups of MAIN. Each subgroup is encouraged to distribute its portion of Operating Reserve among all member systems and over as many generating units as possible. Such distribution will best assure the availability of such reserve in the event of loss or generating capacity and the operation of transmission facilities within established design criteria during contingency conditions.

Maintenance of Operating Reserve Requirement

In the event of any contingency which reduces the Operating Reserve level for a system, or subgroup, below the recommended minimum value set by these criteria, it is the obligation of the deficient system, or subgroup, to restore its Operating Reserve to the stated minimum level as soon as practicable. This may be accomplished by appropriate action within the deficient system, or subgroup, and/or by scheduling energy receipts from other adjacent systems. If excess daily Operating Reserves are unavailable to meet the foregoing, the available Operating Reserves within MAIN is redistributed by scheduled receipts and deliveries to the extent necessarv to assure maximum bulk power system reliability within MAIN.

Administration Guide

The Administration Guide provides only the minimum level of Operating Reserve to be carried out by MAIN. It is recognized that in some special circumstances good operating practices will dictate a reserve larger than specified by this Guide.

The calculation of minimum Operating Reserve and its distribution is in accordance with provisions of the Guide and on the form below as Table 3-7. Since these calculations are dependent upon the largest unit size within subgroups of MAIN and are therefore subject to change when units are placed in commercial service, the recalculation of generating reserves does not require endorsement of the MAIN membership, except at each Annual Meeting or upon revision of the Guide as recommended by its Executive Committee.

Table 3-7

MAIN GUIDE NO. 5

	Subgroups			MAIN
	CE	IL-MO	WUMS	TOTAL
Winter normal rating of largest unit in commercial operation MW	1,040	605	505	2,150
Distribution of Operating Reserve				
Percentage	48.4	28.1	23.5	100
MW	755	439	366	1,560
Minimum level of Spinning Reserve	377	220	183	780

Effective Date: March 25, 1977

When a larger unit which previously existed in a subgroup of MAIN is declared to be in commercial service, the owning company notifies the Chairman of the MAIN Operating Committee. The Chairman calculates the new Operating Reserve requirements of each subgroup and notifies the subgroups of the new requirement.

Whenever the largest unit in MAIN is out of service or its capability is significantly limited, the MAIN Coordination Center issues a revision of Operating Reserve requirements to match required Operating Reserve to actual risk level. This procedure conserves fuel which would be consumed by carrying unnecessary spinning reserve when all major units are operating satisfactorily.

The MAIN Operating Committee evalutates annually the effectiveness of the minimum Operating Reserve program, based on a critical analysis of the actual performance of each system in MAIN. The Operating Committee makes recommendations for changes in the program if deemed desirable.

Procedures For Coordination of Maintenance Outages of Generation and Transmission Facilities

In general, maintenance schedules are prepared on a sub-regional basis either by power pools or other groupings. Such schedules are prepared with as much lead time as possible to assure that adequacy of the power supply system can be properly reviewed. These generation and transmission outage schedules are directed to the MAIN and adjacent regional coordination centers so that scheduling can be compared with those of other power suppliers to be certain no inadequate and/or unreliable situation will develop. The MAIN Coordination Center keeps a current record of forced and scheduled outages and reserve margins for each group of member companies.

Coordination of Area Control Centers

The MAIN region utilizes a teletype communications system to which regular members in the States of Missouri, Illinois and Wisconsin are connected as shown on Figure 3-1. A terminal connected to this network is also located in the MAPP Coordination Center. This system may be used by any member of MAIN or MAPP or by the MAIN and MAPP Coordination Centers to broadcast information to the member companies or by one member to contact another. This system has been used primarily to make reports to the members of the current status of generation and transmission facilities and the generating capacity reserve situation.

The MAIN Coordination Center is also connected to the ECAR teletype communications system. Regular communication with the Tennessee Valley Authority (TVA) is accomplished with daily telephone calls. Coordination with the Southwest Power Pool (SWPP) companies is accomplished by the MAIN companies having power dispatching interconnection with the SWPP companies.

In addition to the MAIN teletype network, members can communicate directly to those other members to which they are interconnected using owned or leased dedicated dispatching circuits. Central office telephone facilities and radio are also used. In general, members plan their inter-company communications such that a primary and back-up voice circuit is available. Communication between members and other systems and area control centers in the MAIN area is normally by leased telephone facilities or by use of central office facilities.

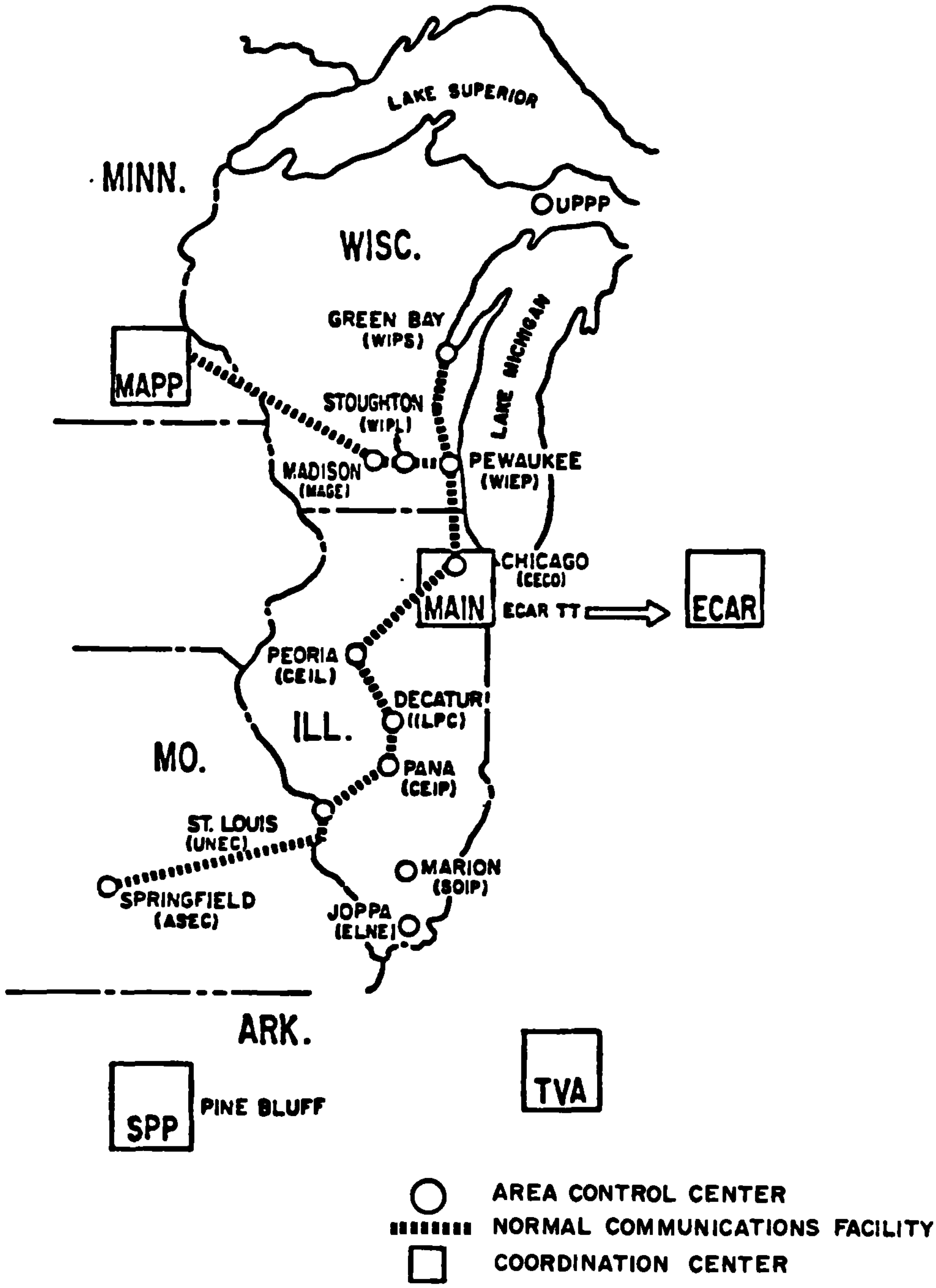

Figure 3-1

1979 MAIN TELETYPE COMMUNICATION NETWORK

MAIN does not have facilities for regional control of generating capacity or major switching stations nor are such facilities planned in the future. Each system controls its own generating capacity in accordance with procedures set forth in the MAIN and NAPSIC operating guides.

The MAIN Coordination Center is located in Lombard, Illinois, a suburb of Chicago. The principal responsibility of the Center is to assure that the region will meet its load requirements with a maximum interconnected system reliability. To accomplish this, the Center functions to coordinate scheduled outages of principal transmission and generation facilities, provide information to regional system operators relating to the status of transmission facilities and generating capacity reserves, analyze system operation and unusual conditions, and assist members during critical periods to assure coordination of interconnected systems operating throughout MAIN and adjacent areas.

The Coordination Center has a mini-computer which is tied in with the large computers of Commonwealth Edison Company. With this equipment the Coordination Center Staff participates in system studies conducted by the MAIN Transmission Task Force. The equipment is also utilized to perform studies of regional transmission operation when unusual operating conditions develop.

There are no plans to significantly change the functions of the area control centers in MAIN.

3.9 MAIN REGIONAL SUMMARY*

Table 3-8 shows the most probable generation mix to the year 2000 for MAIN. The most probable plan differs from utilities conceptual planning framework in (a) slightly increased coal-fired capacity, (b) reduced nuclear capacity, and (c) more effective utilization of off-peak thermal energy. It is projected that the market potential for under-ground or conventional pumped storage is likely to represent as much as 6% in the year 2000. In addition, it is likely that other electric energy generation sources and energy storage systems will appear before the year 2000. It is estimated that other sources, particularly battery and thermal storage systems, will provide approximately 3% of MAIN's system capacity by the year 2000.

The probable generation mixes for Commonwealth Edison sub-region for the Years 1985, 1990, 1995 and 2000 are shown in the Table 3-9. It is likely that nuclear additions will continue throughout the period because of general economic attractiveness over coal. However, coal plant additions probably will continue despite strict air quality standards to maintain diversification of generation sources. The potential for large conventional hydroelectric development in the Commonwealth Edison sub-region is virtually non-existent due to the relatively flat topography. However, there is large potential for underground hydroelectric pumped-storage owing to a large nuclear and coal generating base and the availability of suitable sites such as the Tunnel and Reservoir Project (TARP) of the Greater Chicago Area.

*Source: Ref. 3-3

Table 3-8

MAIN GENERATION MIX

(Percent of Total Capability)

Generation Type	1985 (%)	1990 (%)	1995 (%)	2000 (%)
Base				
Nuclear	26-27	23-25	22-25	22-25
Coal	36-38	38-40	40-42	40-42
Intermediate				
Coal	18-20	23-25	24-27	25-28
Oil	5-7	3-5	2-3	1-2
Conv. Hydro	0-1	0-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	8-10	8-10	6-8	4-6
Gas	1	0-1	0-1	0-1
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	1	1	1-3	2-6
Other	0	0-1	0-1	1-2
Total Capability (GW)	56.5	68.1	82.5	100.0

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

It is estimated that underground pumped-storage could represent as much as 7% of the total generating capability in the year 2000. Existing oil-fired units are projected to remain in service, although some may be converted to coal. It is unlikely that any new oil-fired units will be added.

Table 3-9

COMMONWEALTH EDISON SUB-REGION GENERATION MIX

(Percent of Total Capability)

Generation Type	1985 (%)	1990 (%)	1995 (%)	2000 (%)
Base				
Nuclear	47-49	43-45	38-40	36-40
Coal	15-17	18-20	22-25	23-26
Intermediate				
Coal	14-16	18-20	21-23	22-25
Oil	7-8	5-7	2-4	0-2
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	12-13	10-12	8-10	5-8
Pumped Storage	0	0	0-4	3-7
Other	0	0-1	0-1	1-2
Total Capability (GW)	24.2	28.4	35.1	43.4

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Illinois Missouri Sub-Region

The Illinois-Missouri sub-region generation mix projected to the year 2000 is shown in Table 3-10. Coal-fired steam plants are expected to supply a large portion of the base load. A number of nuclear plants are scheduled to be operational by 1985. After 1995, addition of hydroelectric pumped-storage and other energy storage systems is likely. Conventional hydroelectric development is expected to be small.

Table 3-10

ILLINOIS-MISSOURI SUB-REGION GENERATION MIX

(Percent of Total Capability)

Generation Type	1985 (%)	1990 (%)	1995 (%)	2000 (%)
Base				
Nuclear	10-11	8-10	7-9	7-9
Coal	51-52	52-54	53-55	53-55
Intermediate				
Coal	22-24	23-25	24-25	25-27
Oil	4-5	3-5	2-4	1-2
Conv. Hydro	1-1	1-1	0-1	0-1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	6-8	5-7	4-6	3-5
Gas	0-1	0-1	0	0
Conv. Hydro	0-1	0-1	0-1	0-1
Pumped Storage	1	1	1	1-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	22.0	27.4	32.9	39.2

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

Wisconsin-Upper Michigan Sub-Region

The Wisconsin-Upper Michigan sub-region generation mix projected to the year 2000 is shown on Table 3-11. The emphasis is expected to be placed on the construction of new coal-fired plants. Oil-fired peaking capacity is expected to decrease slightly as old units are retired. By the year 2000 pumped storage is likely to be introduced.

Table 3-11

WISCONSIN-UPPER MICHIGAN SUB-REGION GENERATION MIX

(Percent of Total Capability)

Generation Type	1985 (%)	1990 (%)	1995 (%)	2000 (%)
Base				
Nuclear	14-15	13-15	12-15	12-15
Coal	50-52	50-52	50-53	50-53
Intermediate				
Coal	22-24	23-25	24-26	24-26
Oil	2-3	1-2	1-2	0-1
Conv. Hydro	1	1	1	1
Other	0	0-1	0-1	1-2
Peaking				
Coal 1/	-	-	-	-
Oil	7-8	6-8	5-7	4-6
Conv. Hydro	1	0-1	0-1	0-1
Pumped Storage	0	0	0	0-5
Other	0	0-1	0-1	1-2
Total Capability (GW)	10.3	12.3	14.5	17.3

1/ All coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal-fired plants will be capable of operating near the top of the load curve.

3.10 ENVIRONMENTAL IMPACTS

At every turn, the production and distribution of electricity impacts the environment. Generation often produces a combination of adverse air and water quality impacts, solid waste disposal problems, and adverse land-use consequences. Transmission and distribution lines use significant amounts of land for right-of-way, and overhead lines can produce adverse aesthetic impacts and possible adverse electrostatic and electromagnetic field effects.

At present, Federal environmental concerns are institutionalized within the planning process by the National Environmental Policy Act process. Control mechanisms vary at the State and local levels. The degree to which future power facilities will be allowed to impact the environment is still unresolved and debated. Tighter standards over air and water emissions, solid waste, and carbon dioxide emissions could create severe difficulties. Obtaining additional rights-of-way for transmission lines will create significant problems unless the technologies of underground and superconductive high-voltage transmission, which are prohibitively costly at present, improve substantially. Approvals for surface-mining of coal and attendant land reclamation are currently uncertain and potentially subject to increased environmental control. The issues surrounding nuclear generation include: (1) need for adequate storage for spent nuclear fuel and for a nuclear waste management program for ultimate disposal of radioactive waste; (2) unresolved questions about the safety of nuclear powerplants operations; and, (3) safety concerns in the transportation of nuclear materials.

REFERENCES

3-1. Harza Engineering Company, "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study, Phase I - 1978 Electric Power Demand and Supply", Institute for Water Resources, Fort Belvoir, Virginia, April 1979.

3-2. U.S. Army Corps of Engineers, Institute for Water Resources," Estimates of National Hydroelectric Power Potential at Existing Dams", Fort Belvoir, Virginia, July 1977.

3-3. Harza Engineering Company, "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study, Phase II - Future Electric Power Damand and Supply", Institute for Water Resources, March 1980.

3-4. Stanford Research Institute, "Fuel and Energy Price Forecasts", Electric Power Research Institute, September 1977.

3-5. Foster Associates, Inc., "Fuel and Energy Price Forecasts", Electric Power Research Instutute EA-411, March 1977.

3-6. Federal Energy Regulatory Commission, "Preliminary Generalized Power Values for National Hydropower Study", 1978.

3-7. Electric Power Survey Commission, "Technical Assessment Guide", EPRI PS-866-SR, June 1978.

Chapter 4

DEMAND SUMMARY

4.1 CAPACITY AND ENERGY DEMAND

MAIN has a summer peak demand of 33.4 GW as shown on Table 4-1. The Commonwealth Edison, Illinois-Missouri and Wisconsin-Upper Michigan System sub-regions have summer peaks of 13.9, 13.0, and 6.5 GW, respectively. The annual historic peaks for MAIN and the three sub-regions are shown in Table 4-2 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 sub-regions are also shown in Table 4-2. 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 sub-regions as well.

Table 4-1

ANNUAL ENERGY, PEAK DEMAND AND LOAD FACTOR

	Annual Energy GWh	Peak 1/ Demand MW	Month of peak Demand	Annual Load Factor %
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
MAIN Total	161,081	33,403	July	55.0

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

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

4.2 LOAD CHARACTERISTICS

The monthly energy and peak demands for 1977 are shown on Table 4-3. 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

Table 4-2

HISTORIC ANNUAL ENERGY, PEAK DEMAND AND LOAD 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, 1 April 1978.

2/ Information obtained from MAIN in November 15, 1978 letter.

Table 4–3

MONTHLY ENERGY AND PEAK DEMANDS

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.	Annual
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	33,404
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 Nergy, 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	66.9	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

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

Table 4–4

SYSTEM LOAD VARIATIONS 1/

Representative Utilities of 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	76.3	83.9	71.1	73.1	73.7	9,606		45,196	53.7
Central Illinois Public Service Co.	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	2,856	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 Corp.	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.

Table 4–5

RESOURCES, DEMAND AND MARGIN

	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

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

Table 4-4. The first full weeks in April, August and December in 1977 were chosen to represent the variations in demand on the system relative to the annual peak for each utility. The table 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 durations curves for representative utilities in MAIN are shown in Figures 4-1, 4-2, and 4-3.

4.3 DEMAND-SUPPLY BALANCE

The MAIN Reliability Council primarily is a summer peaking system. All three sub-regions 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 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 4-5. All sub-regions have adequate reserve margins.

4.4 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 4-6. Although MAIN is a net exporter of power annually (see Table 4-6), it is a net importer for the summer. Commonwealth Edison is the only sub-region of the three that is a net importer for that season. The relative magnitude of the imports for Commonwealth Edison to those of the other sub-regions is responsible for MAIN's summer net import status.

Table 4-6

EMERGENCY TRANSFER CAPABILITIES BETWEEN RELIABILITY COUNCILS (MW)

From	Amount (MW)	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

Source: FERC, "8th Annual Reviews & Overall Reliability of the North American Bulk Power Systems", August 1978.

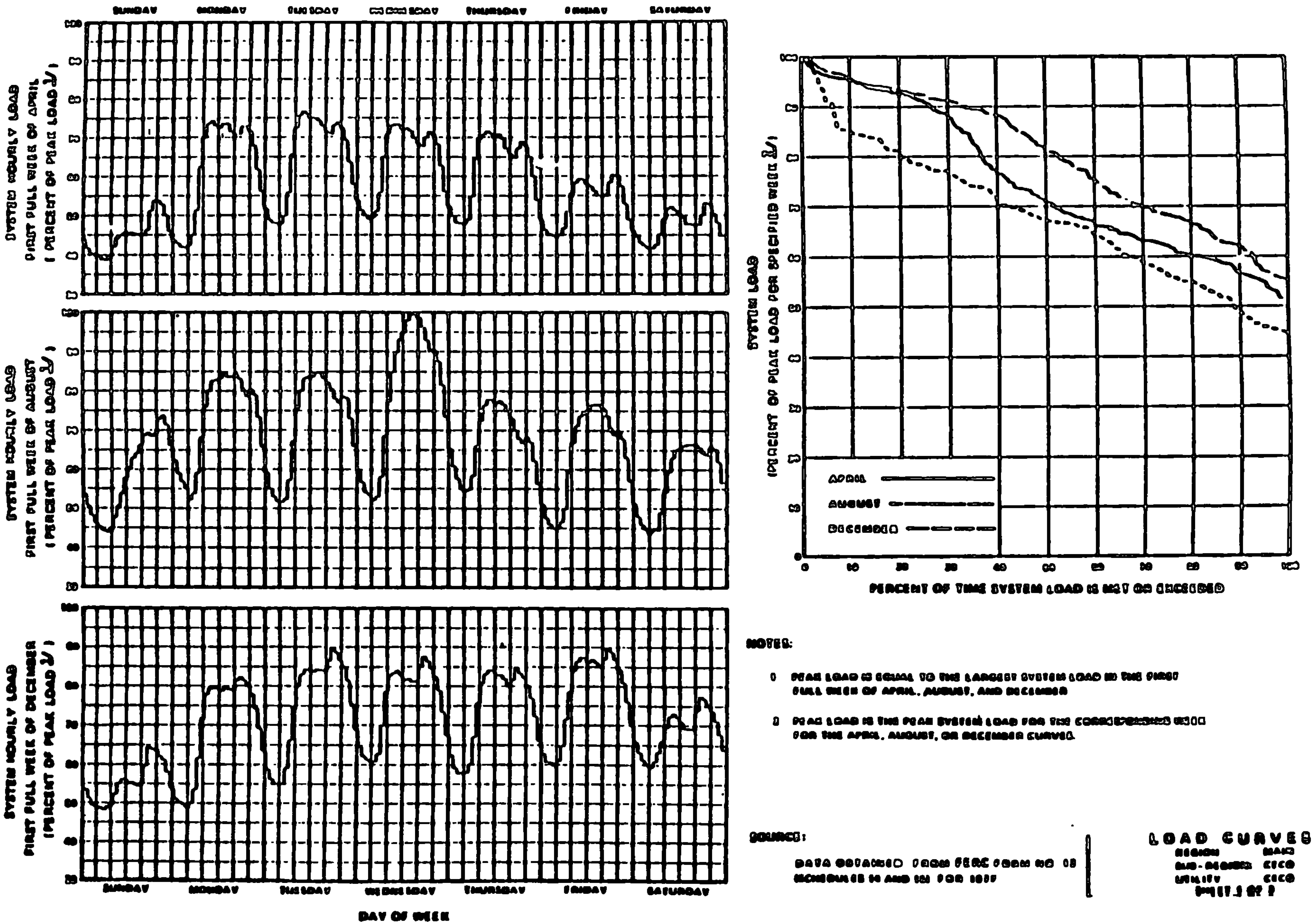

Figure 4-1

WEEKLY LOAD DURATION CURVES - - CECO

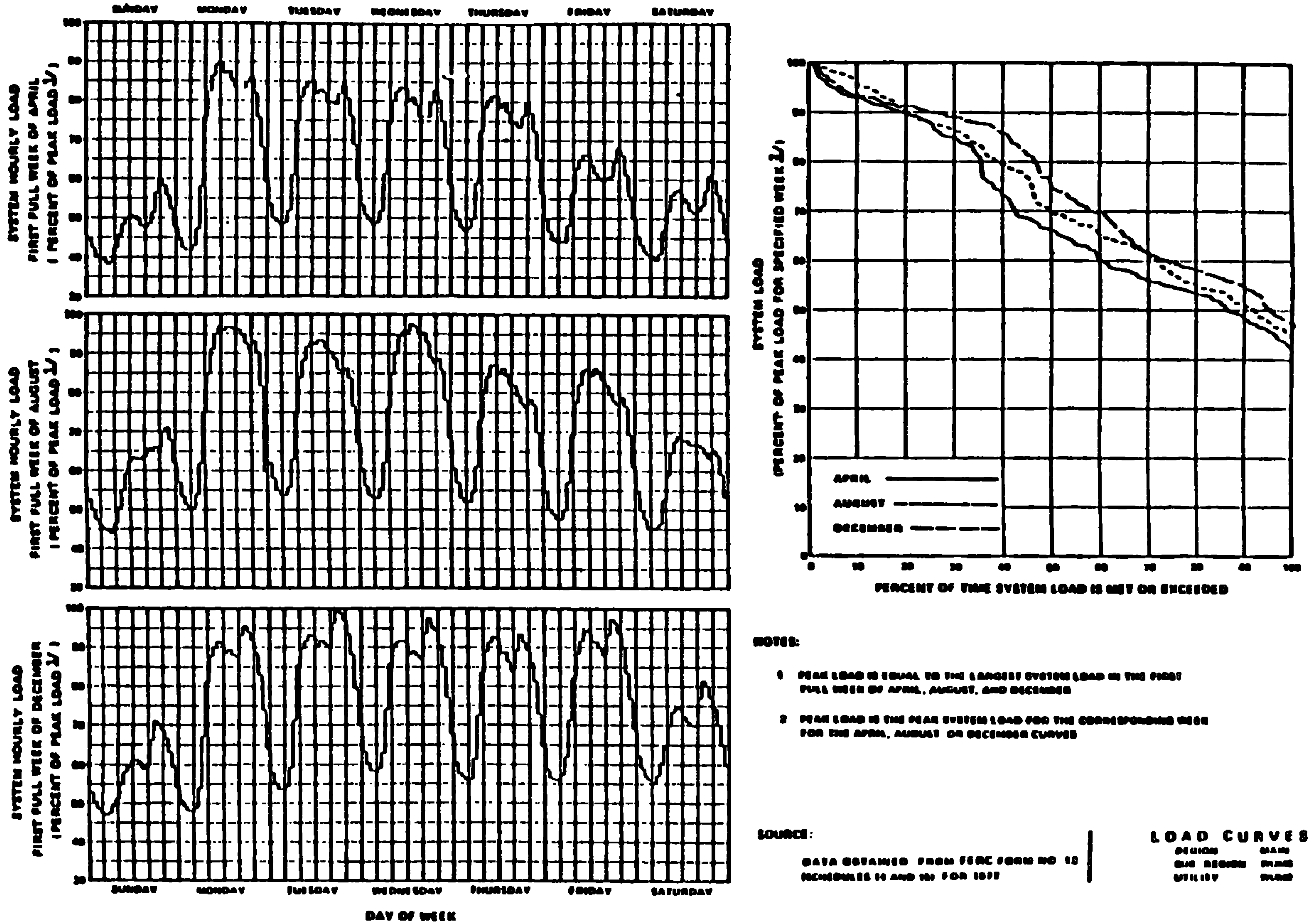

Figure 4-2

WEEKLY LOAD DURATION CURVES - - WUMS

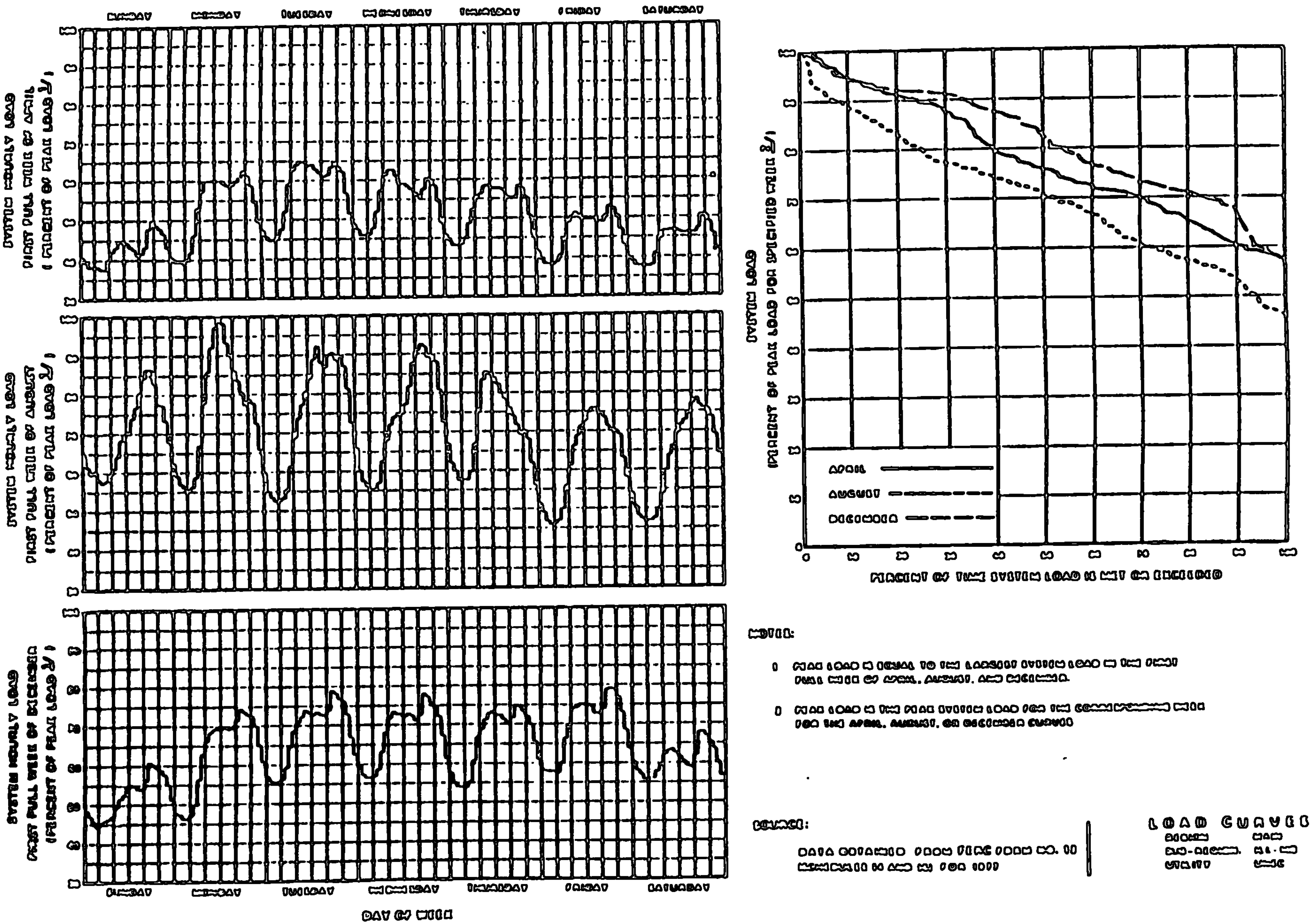

Figure 4-3

WEEKLY LOAD DURATION CURVES - -ILLINOIS - MISSOURI

4.5 RESERVE MARGINS AND REGIONAL SYSTEM RELIABILITY

Commonwealth Edison's reserve margin criteria are 14% of the summer peak demand period and 24% of the winter. The Illinois-Missouri System sub-region 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 sub-region specifies a minimum reserve capacity of 15% of the adjusted demand. Table 4-5 shows the utility to be well within its reserve requirements. These reserve criteria have produced a more reliable system.

4.6 FUTURE ELECTRIC POWER DEMAND*

To define a reasonable range of future electricity demands which reflect different assumptions, such as population and economic growth rates, impact of various conservation programs, load management, and energy pricing policies, three electricity projections (Projections I, II, and III) were developed by HARZA Engineering Company from published and readily available information and data on electricity demand forecasts (Ref. 4-2, 4-3 and 4-4).

Projection I was derived from the utilities. Each NERC region is required to forecast annually, electric demand and supply for the next ten years, based on utility projection, and provide "conceptual planning" projection for the subsequent eleven to twenty years. The reports filed by the utilities through FERC to the Department of Energy on April 1, 1979 were the latest available source for this study (Ref. 4-5).

Projection II was derived from forecasts made by the Institute for Energy Analysis (IEA) at the Oak Ridge Associated Universities in September 1976 (Ref. 4-3). The main finding of the IEA study is that both the Gross National Product (GNP) and energy demand are likely to grow significantly more slowly than has been assumed in most analysis of energy policy. From this study, the annual per capita electric energy consumption growth rate in the United States is projected to be 2.6% for the period 1978-2000.

Projection III is based on the "Consensus Forecast of U.S. Electricity Demand" (Ref. 4-6). The electricity demand in the "Consensus Forecast" was derived from the energy demand which represents an average of 15 forecasts made by private and federal economists in the post-embargo period. They was conservation oriented and not the historical growth forecast that usually were made in pre-embargo period. Based on this study, the annual per capita electric energy consumption is expected to decrease from 4.5% between 1978 to 1985 to 3.2% between 1995 and 2000.

Projections II and III are based on per capita electric energy growth rates. The 1978 per capita consumption for each region and sub-region is used as the base condition. To compute the per capita energy consumption, the OBERS population forecasts were adjusted to reflect the latest (1978)

*Source: Ref. 4-1

population estimates published by the Department of Commerce. The revised population growth rates provide more realistic near future trends in population (Table 4-2) than the estimates based on the original OBERS forecast (Table 4-7).

Table 4-7

POPULATION AVERAGE ANNUAL GROWTH RATE FOR THE PERIOD

Region Sub-Region	1970-1978 %	1978-1985 %	1985-1990 %	1990-1995 %	1995-2000 %
MAIN					
CECO	0.15	0.5	0.8	0.7	0.7
ILL-MO	0.28	0.4	0.6	0.4	0.4
WUMS	0.72	0.7	0.6	0.5	0.5

Tables 4-8 to 4-11 present the detailed demand summary for the three projections. From Projections I, II, and III, a "median" electricity projection was selected and considered to be representative of future regional (or sub-regional) demands.

Energy Demand

The future annual "median" electric energy consumption in MAIN is expected to grow from 168,800 GWh in 1978 to 232,500 GWh in 1985, representing a compound annual growth rate of 4.7%. By the year 2000, electric energy consumption is expected to grow to about 421,400 GWh, representing a compound annual rate of 4.2% between 1978 and 2000.

The Wisconsin-Upper Michigan sub-region is expected to have the lowest average growth-rate in energy demand, at an annual growth rate of 3.8% between 1978 and 2000. The Illinois-Missouri sub-region is expected to experience steady decline in the growth rate of energy demand, from an average of 4.9% between 1978 and 1985 to 3.6% between 1995 and 2000. Due to a projected larger increase in population, the Commonwealth Edison sub-region has a steadier growth rate, averaging 4.4% over the period 1978-2000.

Peak Demand

Presently, the three sub-regions of MAIN are summer peaking regions. The peak demands in the Illinois-Missouri and Commonwealth Edison sub-regions are expected to continue occurring during the summer at least until the year 2000. Some utilities in the Wisconsin-Upper Michigan sub-region currently have and will continue to have winter peaks. The peak demand in MAIN is expected to grow from 33,200 MW in 1978 to 84,700 MW in 2000

Table 4-8
ELECTRIC POWER DEMAND
MID AMERICA INTERPOOL NETWORK REGION (MAIN)
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	19122.	.5	19819.	.7	20523.	.6	21115.	.6	21726.	.6
PROJECTION I										
Per Capita Consumption (MWH)	8.8	4.2	11.7	3.7	14.1	3.7	16.9	3.8	20.3	3.9
Total Demand (Thousand GWH)	188.8	4.7	232.8	4.4	289.4	4.3	356.8	4.4	441.6	4.5
Peak Damend (GW)	33.2	5.1	46.9	4.3	58.0	4.3	71.6	4.4	88.7	4.6
PROJECTION II										
Per Capita Consumption (MWH)	8.8	2.6	10.6	2.6	12.0	2.6	13.6	2.6	15.5	2.6
Total Demand (Thousand GWH)	168.8	3.1	209.3	3.3	246.2	3.2	287.6	3.2	335.9	3.2
Peak Demand (GW)	33.2	3.5	42.2	3.2	49.3	3.2	57.7	3.2	67.5	3.3
PROJECTION III										
Per Capita Consumption (MWH)	8.8	4.5	12.0	4.0	14.5	3.3	17.1	3.2	20.0	3.8
Total Demand (Thousand GWH)	188.8	5.0	238.0	4.7	299.5	3.9	362.0	3.8	435.4	4.4
Peak Demand (GW)	33.2	5.4	47.9	4.6	60.0	3.9	72.6	3.8	87.5	4.5
MEDIAN PROJECTION										
Per Capita Consumption (MWH)	8.8	4.1	11.7	3.6	14.0	3.3	16.5	3.3	19.4	3.6
Total Demand (Thousand GWH)	188.8	4.7	232.5	4.3	287.5	3.9	347.9	3.9	421.4	4.2
Peak Demand (GW)	33.2	5.0	46.8	4.2	57.6	3.9	69.8	3.9	84.7	4.3
Margin (Percent)			20.7		18.2		18.1		18.1	
Resources To Serve Demand (GW)			56.5		68.1		82.5		100.0	
Load Factor (Percent)	58.0		56.7		57.0		56.9		56.8	

*NOTE: The growth rates are average annual compounded rates over the period.

Table 4-9

ELECTRIC POWER DEMAND

COMMONWEALTH EDISON SUB-REGION

(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSAND)	9493.	.5	9830.	.8	10230.	.7	10593.	.7	10969.	.7
PROJECTION I										
Per Capita Consumption (MWH)	7.2	4.1	9.5	3.6	11.3	3.6	13.5	3.6	16.1	3.8
Total Demand (Thousand GWH)	67.9	4.7	93.4	4.4	115.8	4.3	143.0	4.3	176.8	4.4
Peak Demand (GW)	13.7	5.3	19.7	4.3	24.3	4.3	30.0	4.3	37.1	4.6
PROJECTION II										
Per Capita Consumption (MWH)	7.2	2.6	8.6	2.6	9.7	2.6	11.1	2.6	12.6	2.6
Total Demand (Thousand GWH)	67.9	3.1	84.1	3.4	99.6	3.3	117.6	3.3	138.0	3.3
Peak Demand (GW)	13.7	3.8	17.7	3.3	80.9	3.3	24.6	3.3	29.0	3.5
PROJECTION III										
Per Capita Consumption (MWH)	7.2	4.5	9.7	4.0	11.8	3.3	13.9	3.2	16.3	3.8
Total Demand (Thousand GWH)	67.9	5.0	95.7	4.8	121.1	4.0	147.6	3.9	178.9	4.5
Peak Demand (GW)	13.7	5.7	20.2	4.7	25.4	4.0	31.0	3.9	37.5	4.7
MEDIAN PROJECTION										
Per Capita Consumption (MWH)	7.2	4.1	9.5	3.6	11.3	3.6	13.5	3.6	16.1	3.8
Total Demand (Thousand GWH)	67.9	4.7	93.4	4.4	115.8	4.3	143.0	4.3	176.8	4.4
Peak Demand (GW)	13.7	5.3	19.7	4.3	24.3	4.3	30.0	4.3	37.1	4.6
Margin (Percent)			23.0		17.0		17.0		17.0	
Resources To Serve Demand (GW)			24.2		28.4		15.1		43.4	
Load Factor (Percent)	56.6		54.1		54.4		54.4		54.4	

*NOTE: The growth rates are average annual compounded rates over the period.

Table 4-10
ELECTRIC POWER DEMAND
ILLINOIS-MISSOURI SUB-REGION
(1978-2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSANDS)	5593.	.4	5751.	.6	5962.	.4	6045.	.4	6167.	.4
PROJECTION I										
Per Capita Consumption (MWH)	11.4	4.6	15.6	4.3	19.2	4.3	23.7	4.3	29.3	4.4
Total Demand (Thousand GWH)	63.8	5.0	89.6	4.9	113.8	4.7	143.2	4.7	180.5	4.8
Peak Demand (GW)	13.0	5.1	18.4	4.7	23.2	4.7	29.2	4.7	36.8	4.8
PROJECTION II										
Per Capita Consumption (MWH)	11.4	2.8	13.7	2.6	15.5	2.6	17.6	2.6	20.1	2.6
Total Demand (Thousand GWH)	63.8	3.0	78.5	3.2	92.0	3.0	106.7	3.0	183.7	3.1
Peak Demand (GW)	13.0	3.1	16.1	3.1	18.8	3.0	21.7	3.0	25.2	3.1
PROJECTION III										
Per Capita Consumption (MWH)	11.4	4.5	15.5	4.0	18.9	3.3	22.2	3.2	26.0	3.8
Total Demand (Thousand GWH)	63.8	4.9	89.3	4.6	111.9	3.7	134.3	3.6	160.4	4.3
Peak Demand (GW)	13.0	5.0	18.3	4.5	22.8	3.7	27.4	3.6	32.7	4.3
MEDIAN PROJECTION										
Per Capita Consumption (MWH)	11.4	4.5	15.5	4.0	18.9	3.3	22.2	3.2	26.0	3.8
Total Demand (Thousand GWH)	63.8	4.9	89.3	4.6	111.9	3.7	134.3	3.6	160.4	4.3
Peak Demand (GW)	13.0	5.0	18.3	4.5	22.8	3.7	27.4	3.6	32.7	4.3
Margin (Percent)			20.0		20.0		20.0		20.0	
Resources To Serve Demand (GW)			22.0		27.4		32.9		39.2	
Load Factor (Precent)	56.0		55.6		56.0		56.0		56.0	

*NOTE: The growth rates are average annual compounded rates over the period.

Table 4–11
ELECTRIC POWER DEMAND
WISCONSIN–UPPER MICHIGAN SUB–REGION
(1978–2000)

	1978	7-YEAR GROWTH RATE*	1985	5-YEAR GROWTH RATE*	1990	5-YEAR GROWTH RATE*	1995	5-YEAR GROWTH RATE*	2000	22-YEAR OVERALL GROWTH RATE*
POPULATION (THOUSAND)	4036.	.7	4238.	.6	4367.	.5	4477.	.5	4590.	.6
PROJECTION I										
Per Capita Consumption (MWH)	9.2	3.6	11.8	3.1	13.7	2.9	25.8	3.1	18.4	3.2
Total Demand (Thousands GWH)	37.1	4.3	49.8	3.7	59.8	3.4	70.6	3.6	84.3	3.8
Peak Demand (GW)	6.5	4.4	8.8	3.6	10.5	3.4	12.4	3.6	14.8	3.8
PROJECTION II										
Per Capita Consumption (MWH)	9.2	2.6	11.0	2.6	12.5	2.6	14.2	2.6	16.2	2.6
Total Demand (Thousands GWH)	37.1	3.3	46.6	3.2	54.6	3.1	63.7	3.1	74.2	3.2
Peak Demand (GW)	6.5	3.4	8.2	3.1	9.6	3.1	11.2	3.1	13.0	3.2
PROJECTION III										
Per Capita Consumption (MWH)	9.2	4.5	12.5	4.0	15.8	3.3	17.9	3.2	21.0	3.8
Total Demand (Thousands GWH)	37.1	5.2	53.0	4.6	66.5	3.8	80.1	3.7	96.2	4.4
Peak Demand (GW)	6.5	5.4	9.4	4.5	11.7	3.8	14.1	3.7	16.9	4.4
MEDIAN PROJECTION										
Per Capita Consumption (MWH)	9.2	3.6	11.8	3.1	13.7	2.9	15.8	3.1	18.4	3.2
Total Demand (Thousands GWH)	37.1	4.3	49.8	3.7	59.8	3.4	70.6	3.6	84.3	3.8
Peak Demand (GW)	6.5	4.4	8.8	3.6	10.5	3.4	12.4	3.6	14.8	3.8
Margin (Percent)			17.0		17.0		17.0		17.0	
Resources to Serve Demand (GW)			10.3		12.3		14.5		17.3	
Load Factor (Percent)	65.2		64.6		65.0		65.0		65.0	

*NOTE: The growth rates are average annual compounded rates over the period.

Load Factor

MAIN had an annual load factor of 58% in 1978. From the projected peak and energy demands forecast by the utilities, future annual load factors for the MAIN region are expected to average 57%. The Wisconsin-Upper Michigan sub-region has the highest load factor, and is projected to remain at 65%. The two other sub-regions have projected annual load factors between 54% and 56%.

Characteristics of Electric Loads

Table 4-12 presents a breakdown of loads (base, intermediate, and peak) for each of these utilities. These percentages are representative of each season. During each season, the loads may vary by several percents.

Table 4-12

LOAD DISTRIBUTION IN MAIN
(Percent of Annual Peak Load)

Representative Utility	Base (%)	Intermediate (%)	Peak (%)
Commonwealth Edison Sub-Region:			
Commonwealth Edison Company			
Off Season	44	14	5
Summer	59	26	15
Winter	56	14	6
Annual	59	26	15
Wisconsin-Upper Michigan Sub-Region:			
Wisconsin Electric Power Company			
Off Season	46	23	9
Summer	60	28	12
Winter	55	23	9
Annual	60	28	12
Illinois-Missouri Sub-Region:			
Union Electric Company			
Off Season	42	10	4
Summer	61	20	19
Winter	52	10	6
Annual	61	20	19

For the three utilities representative of MAIN, the average annual base load varies between 59% and 61%, and the peak load varies between 12% and 19% of the peak annual demand. The portions of the load considered as base, intermediate or peak are the basis for deriving the generation mix.

REFERENCES

4-1. Harza Engineering Company, "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study - Phase I - 1978 Electric Power Damand and Supply", Institute for Water Resources, Fort Belvoir, Virginia, April 1989.

4-2. Regional Electric Reliability Council, "Reply to Appendix A-2 of Order No. 383-5, Docket R-362", April 1979.

4-3. Institute for Energy Analysis, "U.S. Electricity Supply and Demand to the Year 2000", Oak Ridge National Laboratory, Oak Ridge, May 1977.

4-4. MAIN Regional Reliability Council, "Coordinated Bulk Power Supply Program", Lombard, IL, April 1979.

4-5. National Electric Reliability Council, "2979 Summary of Projected Peak Load, Generating Capability, and Fossil Fuel Requirement," July 1979.

4-6. Lane, J.A, "Consensus Forecast of U.S. Electricity Supply and Demand to the Year 2000", Oak Ridge National Laboratory, Oak Ridge, May 1977.

4-7. U.S. Department of Commerce, Bureau of Census, "Current Population Report-Population Estimates and Projections", Series p-25 No. 799, April 1979.

Chapter 5
METHODOLOGY

5.1 DATA COLLECTION AND SCREENING - STAGE 1

The initial data collection and screening procedures for the National Hydroelectric Power Study were designed to develop a comprehensive, nationwide inventory of the physical potential for hydroelectric power at both developed and undeveloped water resource sites, including dams, navigation locks, and irrigation structures.

Representatives from the Corps of Engineers Divisions were responsible for selecting standards for the initial screening criteria within their Division. The North Central Division (NCD) was responsible for the preparation of this Appendix. MAIN encompasses parts of four of the five Districts of NCD, namely, the Chicago, Rock Island, Detroit and St. Paul Districts. In addition, part of two Districts of the Lower Mississippi Valley Division are also within the Boundary of MAIN, i.e. Memphis and St. Louis Districts and part of one District of Southwest Division (Little Rock) and part of one district of Missouri River Division (Kansas City). District representatives were responsible for obtaining additional data items required, entering them on a data sheet called Form 1 and checking printouts to assure accuracy of inputs into the data base.

Due to study funds available and time required for completion, the scope of the study was limited to sites with a potential of at least 1 megawatt.

An initial 2 weeks was allowed to identify undeveloped sites of 1-MW or greater. Corps Districts used all available studies and reports to screen undeveloped sites for 1-MW potential in one day assuming the release of water equivalent to project storage in a 24-hour period at maximum head. Those undeveloped sites with less than 1-MW potential were screened out using the power formula:

$$P = \frac{Qhe}{11.8} = 0.072\ Qh$$

Where: P=Kilowatts
Q=Average annual discharge in cubic feet per second
h=Available head
e=Efficiency (usually 0.85)

The average annual discharge for each undeveloped site was obtained from a discharge-drainage area curve constructed for each major watershed basin. These curves were developed from actual stream gage locations and observed discharge data.

For a 24-hour period the formula was revised as:

$$P = .072 \times .5Sh \text{ or } P = .036\ Sh, \text{ since } Q = \frac{0.5\ cfs}{A\text{-}F}$$

where S = Storage in Acre-Feet (A-F)

The next effort of stage 1 involved the identification of potential 1-MW sites that already had dams. The effort began with a computer screening of all sites in the 1975 Corps of Engineers National Dam Inventory. The computer screened out all sites that would not result in 1,000 KW.

A data sheet (Form 1) was then completed for each site remaining in the active inventory after meeting the 1-megawatt undeveloped and developed site criterion. The Form 1 data included known or estimated physical data for each developed or undeveloped site: drainage area, latitude and longitude location, a representative stream gage number, average annual flow, existing and undeveloped hydropower, and known site constraints. Form 1 data sheets were prepared for approximately 1,520 sites in the MAIN Reliability Council Area. A sample copy of Form 1 is shown in Figure 5-1.

5.2 DATA COLLECTION AND SCREENING - STAGE 2

The purpose of the second screening was to select those existing and undeveloped dam sites that met basic capacity and economic standards. The sites that met the standards established for this activity were carried forward for further and, more stringent, screening. The principal tasks in this activity were to:

(1) Refine estimates of capacity and energy for all sites in the initial inventory.

(2) Screen all sites on the basis of capacity and economic criteria to identify sites for more detailed study during stage 3.

(3) Review screening to check for consistency and errors.

(4) Modify the computer data base to reflect Division screening results, and establish active and inactive lists of potential sites.

The Corps of Engineers' Hydrologic Engineering Center (HEC) provided technical support and conducted the refining of capacity and energy estimates, as well as the screening, by computer. Each Division was responsible for accessing the computer inventory file and withdrawing the active and inactive lists for its Districts. The Division consolidated the lists after review by each District and updated the inventory file. Each District reviewed the results of the screening to insure that the lists were consistent and accurate.

```
  0 STATUS OF FILE                                DURC I
  1 LAST UPDATE (YR/MO/DY)                         79/02/04
  2 LAST UPDATE (TIME OF DAY)                      22.51.12
  3 USGS BASE SELECTION (0=USER  1=MACH)                  0
  4 FLO-DUR,SEQ-ROUT PARAMETER (0.0-1.0)                 .1
  5 USGS TAPE NO. FOR MONTHLY FLOWS                    19.0
  6 DRAINAGE AREA OF SELECTED BASE                 119000.0
  7 CALCULATED POWER HEAD                              36.0
  8 MAXIMUM CAPACITY ANALYSED FOR SITE                   0.
  9 MINIMUM CAPACITY ANALYSED FOR SITE                   0.
 10 PROJECT ID NUMBER                    (A7)     IA00011
 20 PROJECT NAME                         (A37)    MISSISSIPPI RIVER LOCK + DAM #19
 30 NAME OF STREAM                       (A29)    MISSISSIPPI RIVER
 40 DIVISION                             (A3)     NCD
 50 DISTRICT                             (A3)     NCR
 60 REGION                               (I2)            7
 70 BASIN                                (I2)            9
 80 LATITUDE                             (F5.1)       40.4
 90 LONGITUDE                            (F6.1)       91.4
100 PRIMARY STATE                        (A2)     IA
110 PRIMARY COUNTY                       (I3)          111
120 PRIMARY CONGRESSIONAL DISTRICT(I2)                   1
130 SECONDARY STATE                      (A2)     IL
140 SECONDARY COUNTY                     (I3)           67
150 SECONDARY CONGRESSIONAL DIST         (I2)           19
160 FERC REGIONAL OFFICE                 (A2)
170 FERC POWER SUPPLY AREA               (I2)           -0
180 FERC RIVER BASIN CODE                (I6)           -0
190 FERC SITE CODE                       (I2)           -0
200 FERC STATE CODE                      (I2)           16
210 HYDRAULIC HEIGHT OF DAM (FT)         (F4.0)       48.0
220 MAXIMUM STORAGE (ACRE-FT)            (F8.0)   292000.0
230 HT OF NORMAL RETENTION (FT)          (F4.0)         0.
240 NORMAL STORAGE (ACRE-FT)             (F8.0)   292000.0
250 NORMAL NET POWER HEAD (FT)           (F4.0)       36.0
260 DRAINAGE AREA (SQ. MI.)              (F8.0)   119000.0
270 STREAMFLOW CHARACTERISTICS           (A1)     H
280 MACHINE ESTIMATES DESIRED            (A3)
290 REPRESENTATIVE BASE SELECTED         (I10)     5474500
300 AVERAGE ANNUAL INFLOW (CFS)          (F8.0)   -63118.6
310 KW @ 0.039 X STORAGE X HEAD          (F8.0)   504576.0
320 INSTALLED CAPACITY (KW)              (F8.0)   128000.0
330 AVE ANNUAL ENERGY INSTALLED          (F9.0)   805000.0
340 IDENTIFIED POWER POTENTIAL(KW)(F8.0)   158400.0
350 AVE ANNUAL ENERGY(MWH)POTENTIA(F9.0)   995000.0
360 NEW POWER POTENTIAL EST. (KW)        (F8.0)   478778.9
370 NEW EST AVE ANN ENERGY (MWH)         (F9.0)  1629433.1
380 EXISTING PUT POWER FEATURES          (A68)
390 OWNER                                (A20)    DAEN NCR, UNION ELECT CO
400 OWNER CODE                           (A1)
410 PURPOSES                             (A7)     H N
420 STATUS                               (A2)
430 ACTIVE IN INVENTORY                  (I1)           -0
440 DEPEND OR INDEPEND                   (A1)
450 COMMENT                              (A48)
460 KNOWN POTENTIAL CONSTRAINTS          (A3)
470 COMMENT                              (A48)
480 GENERAL COMMENTS                     (A48)
490 GENERAL COMMENTS                     (A48)
500 GENERAL COMMENTS                     (A48)
600 NEAREST DOWNSTREAM TOWN              (A28)    WARSAW ILLINOIS
```

Figure 5–1

SAMPLE COPY OF FORM 1

```
610 PRIMARY COUNTY NAME          (A10)  LEE
620 ADDITIONAL VALUE 1           (F10.0)        0.
630 ADDITIONAL VALUE 2           (F10.0)        0.
640 ADDITIONAL VALUE 3           (F10.0)        0.
650 ADDITIONAL VALUE 4           (F10.0)        0.
660 ADDITIONAL VALUE 5           (F10.0)        0.

PROPOSED SITE = IA00011      DISTRICT = NCR

   474778.94  CAPACITY (KW)
  1629433.07  AVERAGE ANNUAL ENERGY (MWH)
         .39  AVERAGE ANNUAL PLANT FACTOR
       63.50  DOLLARS /KW
       22.72  MILLS / KWH
    30148.46  CAPACITY VALUE (1000 $)
    37026.12  ENERGY VALUE (1000 $)
    67174.59  ANNUAL BENEFIT (1000 $)
    11138.22  ANNUAL COST (1000 $)
        6.03  B/C RATIO

USGS GAGE NUMBER   5474500 USER SUPPLIED

ARRAY OF RESULTS USED TO SELECT CAPACITY
TYPE OF ANALYSIS CHOSEN= FLOW-DURATION
OBJECTIVE = MAXIMIZE NET BENEFITS
```

FLOW-DUR	18983.44	24669.37	29945.34	35835.43	42869.87	51998.52	64455.92	83839.91	109876.43	155816.44
EXCEEDENCE	.95	.85	.75	.65	.55	.45	.35	.25	.15	.05
DUR (KW)	57843.29	75168.57	91244.64	109191.97	130626.20	158423.28	196399.76	253635.34	333883.75	474778.94
DUR (MWH)	502225.08	639829.55	750379.77	858600.87	970694.10	1092978.80	1226289.57	1373585.77	1508786.28	1629433.07
SEQ (KW)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
SEQ (MWH)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
APF	.99	.97	.94	.90	.85	.79	.71	.62	.52	.39
CAP $/KW	135.50	135.50	135.50	135.50	135.50	135.50	135.50	135.50	135.50	63.50
MILLS/KWH	9.70	9.70	9.70	9.70	9.75	9.81	9.89	9.98	10.08	22.72
COST $/KW	57.04	52.58	49.54	46.81	44.50	38.39	37.58	39.49	33.85	23.46
BENEFITS $	12709349.12	16385867.71	19642332.23	23125977.28	27165770.66	32191127.46	38736777.28	48078422.04	60455498.53	67174587.59
COST $	3299650.62	3952538.80	4520502.99	5110818.67	5812512.26	6082287.23	7380903.58	10014977.76	11303050.51	11138221.27
NET BEN $	9409698.49	12433334.03	15121829.25	18015158.62	21353258.40	26108840.24	31355873.70	38063444.29	49152448.02	56036366.32
B/C RATIO	3.85	4.15	4.35	4.52	4.67	5.29	5.25	4.80	5.35	6.03
SHORT(MWH)	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

```
INCREMENTAL ARRAY


PROPOSED SITE = IA00011      DISTRICT = NCR

   346778.94  CAPACITY (KW)
   824433.07  AVERAGE ANNUAL ENERGY (MWH)
        -.33  AVERAGE ANNUAL PLANT FACTOR
      -72.00  DOLLARS /KW
       12.84  MILLS / KWH
    12804.46  CAPACITY VALUE (1000 $)
    29071.06  ENERGY VALUE (1000 $)
    41875.52  ANNUAL BENEFIT (1000 $)
     5411.19  ANNUAL COST (1000 $)
        7.74  B/C RATIO
```

Figure 5–1 (Concluded)

The stage 2 screening effort involved an HEC computer screening of the sites with Form 1 input data. Two screenings were conducted. The first used the criteria of 50-kilowatts continuous output and a benefit-cost ratio of 1.0 or greater.

Approximately 763 sites in MAIN met these criteria and were tabulated in a preliminary PIF (public information file) list in May 1979. The PIF data were subsequently updated in July 1979, and summarized in a six-volume, July 1979, IWR report titled "Preliminary Inventory of Hydropower Resources."

The second HEC screening of Form 1 data used the following criteria:

(a) 1 megawatt output as specified before; and,

(b) 1.0 or greater benefit-cost ratio;

Approximately 763 sites in MAIN met these criteria. A computer printout listing those sites meeting the criteria was provided to each District by HEC.

5.3 DATA COLLECTION AND SCREENING - STAGE 3 - GENERAL

The primary purpose of this activity was to accumulate the Form 2 data necessary to accomplish the stage 3 first screening of power sites. The primary tasks involved filling out the required data on Form 2 for those sites passing the stage 2 screening. A sample copy of Form 2 is shown in Figure 5-2.

The District compiled the required data in accordance with the instructions contained in Form 2. Each District determined if use of available cost data was desired or whether complete computer evaluation was preferred. Necessary data varied depending on whether the computer cost routines were used or whether the District elected to compute costs using the North Pacific Division (NPD) Cost Manual. Each District updated the computer data base for their area.

The Districts developed additional site data for the 203 MAIN sites that passed the stage 2 screening. This information was compiled on Form 2 and entered in the computer data base by each District. This added information for the Form 2 sites consisted of section, township, and range locations; physical site and valley characteristics taken from topographic maps and tailwater rating curves; and, any general refined data that could be developed.

NCD elected to have all cost estimates developed by computer, using the NPD method.

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FORM2 - ILMNCC0202 - LOCATION AND IDENTIFICATION            DATE: 04/15/80

 1    R2/M U    PROJECT IDENTIFICATION NUMBER . . . . . . . . . . . . . . . . . . .    (A10)  ILMNCC0202
 2 C1 R2/U      PROJECT NAME -20- . . . . . . . . . . . . . . . . . . . . . . . . .   (4A10)  BRANDON RD POOL
 3 R1 R2/U M    ACTIVE IN INVENTORY -430- . . . . . . . . . . . . . . . . . . . . .   (F2.0)  1.
 4 R1 R2/M U    STATUS OF FILE -0- . . . . . . . . . . . . . . . . . . . . . . . .     (A3)  DRC
 5 R1 R2/M      LAST UPDATE (YR/MO/DY) -1- . . . . . . . . . . . . . . . . . . . .    (A10)  80/03/27
 6 R1 R2/M      LAST UPDATE (TIME OF DAY) -2- . . . . . . . . . . . . . . . . . . .   (A10)  17.52.12
 7    R2/M      LAST COMPUTATION DATE (YR/MO/DY) . . . . . . . . . . . . . . . . .    (A10)  80/03/27
 8 R1 R2/M U    INVENTORY OF DAMS IDENTIFICATION NUMBER -10- . . . . . . . . . . .     (A7)  IL00001
 9 R1 R2/M      USGS TAPE NUMBER (USED FOR INFLOW SELECTION) -5- . . . . . . . . .   (F12.0)            17.
10 R1 R2/M      SELECTED GAGE DRAINAGE AREA (SQ MI) -6- . . . . . . . . . . . . . .  (F12.1)        8259.0
11 R1 R2/U M    WEIGHTED NET POWER HEAD (FT) -7- . . . . . . . . . . . . . . . . .   (F12.1)          33.1
12 C1 C2/M      SITE-TO-GAGE DRAINAGE AREA RATIO -8- . . . . . . . . . . . . . . .   (F12.2)           .18
13 C1 C2/M      POWER STORAGE-TO-AVERAGE ANNUAL INFLOW RATIO -9- . . . . . . . . .   (F12.2)            0.
14 C2/M         AVERAGE ANNUAL DISCHARGE PER AREA (CFS/SQ.MI.) . . . . . . . . . .   (F12.2)         -1.31
15              CAPACITY SELECTION CRITERION .(WORD 1 OF 5) . . . . . . . . . . .    (A10)  (13*1.0),(
16              CAPACITY SELECTION CRITERION .(WORD 2 OF 5) . . . . . . . . . . .    (A10)  16*1.0)
17              CAPACITY SELECTION CRITERION .(WORD 3 OF 5) . . . . . . . . . . .    (A10)
18              CAPACITY SELECTION CRITERION .(WORD 4 OF 5) . . . . . . . . . . .    (A10)
19              CAPACITY SELECTION CRITERION .(WORD 5 OF 5) . . . . . . . . . . .    (A10)
20              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
21              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
22              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
23              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
24    R2/U M    FLOW-DURATION ESTIMATE DESIRED -280- . . . . . . . . . . . . . . .     (A3)  YES
25    R2/U M    SEQUENTIAL ANALYSIS DESIRED . . . . . . . . . . . . . . . . . . . .    (A3)  NO
26              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
27              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
28              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
29              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
30              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
31 O1 R2/U      NAME OF STREAM -30- . . . . . . . . . . . . . . . . . . . . . . . .  (3A10)  DES PLAINES R.
32 R1 R2/U      DIVISION -40- . . . . . . . . . . . . . . . . . . . . . . . . . . .    (A3)  NCD
33 R1 R2/U      DISTRICT -50- . . . . . . . . . . . . . . . . . . . . . . . . . . .    (A3)  NCC
34 O1 R2/U      REGION -60- . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (F12.1)            4.0
35 O1 R2/U      BASIN -70- . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (F12.1)            4.0
36 R1 R2/U      LATITUDE -80- . . . . . . . . . . . . . . . . . . . . . . . . . . .   (A10)   41 30.5
37 R1 R2/U      LONGITUDE -90- . . . . . . . . . . . . . . . . . . . . . . . . . . .  (A10)   88  5.8
38 R1 R2/U      PRIMARY STATE -100- . . . . . . . . . . . . . . . . . . . . . . . .    (A2)  IL
39 O1 R2/U      PRIMARY COUNTY -110- . . . . . . . . . . . . . . . . . . . . . . .   (F12.1)          197.0
40 O1 R2/U      PRIMARY COUNTY NAME -610- . . . . . . . . . . . . . . . . . . . . .  (2A10)  WILL
41 O1 R2/U      NEAREST DOWNSTREAM TOWN -600- . . . . . . . . . . . . . . . . . . .  (3A10)  CHANNAHON
42 C1 R2/U      PRIMARY CONGRESSIONAL DISTRICT -120- . . . . . . . . . . . . . . .    (F3.0)  17.
43 O1 D2/U      SECONDARY STATE -130- . . . . . . . . . . . . . . . . . . . . . . .    (A2)
44 O1 D2/U      SECONDARY COUNTY -140- . . . . . . . . . . . . . . . . . . . . . . .  (F4.0)   0.
45 O1 D2/U      SECONDARY COUNTY NAME . . . . . . . . . . . . . . . . . . . . . . .  (2A10)
46 O1 D2/U      SECONDARY CONGRESSIONAL DISTRICT -150- . . . . . . . . . . . . . .    (F3.0)  0.
47 O1 R2/M      FERC REGIONAL OFFICE -160- . . . . . . . . . . . . . . . . . . . . .   (A2)  CH
48 R1 R2/U      FERC POWER SUPPLY AREA -170- . . . . . . . . . . . . . . . . . . . .  (F3.0)  1.
49 O1 D2/U      FERC RIVER BASIN CODE -180- . . . . . . . . . . . . . . . . . . . .   (F7.0)  838780.
50 O1 D2/U      FERC SITE CODE -190- . . . . . . . . . . . . . . . . . . . . . . . .  (F3.0)  9.
51 O1 D2/U      FERC STATE CODE -200- . . . . . . . . . . . . . . . . . . . . . . .   (F3.0)  17.
52 O1 R2/M      ELECTRIC RELIABILITY COUNCIL -310- . . . . . . . . . . . . . . . . .   (A5)  MAIN
53              ELECTRIC RELIABILITY COUNCIL SUB-REGION . . . . . . . . . . . . . .   (A10)
54              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
55              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)
56              RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . . .   (A10)

FORM2 - ILMNCC0202 - PHYSICAL CHARACTERISTICS               DATE: 04/15/80

57    R2/U      TYPE OF DAM . . . . . . . . . . . . . . . . . . . . . . . . . . . .    (A2)  PG
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Figure 5–2

SAMPLE COPY OF FORM 2

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60 C1 B2/U    OWNER =390= . . . . . . . . . . . . . . . . . . . . . . . . .
61 C1 B2/U    OWNER CODE =400= . . . . . . . . . . . . . . . . . . . . . .   (A1)  C
62 C1 B2/U    PURPOSES =410= . . . . . . . . . . . . . . . . . . . . . . .   (A7)  N
63 01 B2/U    STATUS =420= . . . . . . . . . . . . . . . . . . . . . . . .   (A2)  OP
64 C1 B2/U    EXISTING FEATURES FOR POWER =380= . . . . . . . . . . . . .  (5A10) FOUNDATION FOR FUTURE POWERHOUSE

65 C1 B2/U    DEPENDENT OR INDEPENDENT =440= . . . . . . . . . . . . . . .   (A1)  I
66 01 B2/U    COMMENT =450= . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

67= 76        SYSTEM SEQUENCE
      02/U    PROJ  67           69           71           73           75      (A7)
      02/U    ABOVE 68           70           72           74           76      (A7)
77            RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
78            RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
79            RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
80            ELEVATION OF TOP OF DAM (FT,MSL) . . . . . . . . . . . . . .  (F12.1)  000000000000
81 B2/U       HEIGHT OF DAM (FT) . . . . . . . . . . . . . . . . . . . . .  (F12.1)          45.0
82 B2/U       CREST LENGTH (FT) . . . . . . . . . . . . . . . . . . . . . .  (F12.1)       10250.0
83 B2/U       SITE CROSS-SECTIONAL CLASSIFICATION . . . . . . . . . . . . .   (A1)  A
84 B2/U       SITE ARRANGEMENT CLASSIFICATION . . . . . . . . . . . . . . .   (A1)  M
85 B2/U       WATERWAY LENGTH (FT) . . . . . . . . . . . . . . . . . . . .  (F12.0)            0.
86 B2/U       WATERWAY DESIGN FLOW (CFS) . . . . . . . . . . . . . . . . .  (F12.0)            0.
87 B2/U       HEIGHT TO TOP OF FLOOD CONTROL POOL (FT) . . . . . . . . . .  (F12.1)           0.
88 B2/U       CUMULATIVE STORAGE AT TOP OF FLOOD CONTROL POOL (AC FT) . .  (F12.0)            0.
89 B2/U       SURFACE AREA AT TOP OF FLOOD CONTROL POOL (AC) . . . . . . .  (F12.0)            0.
90 B2/U       MAXIMUM OUTFLOW CAPACITY AT TOP OF FLOOD CONTROL POOL (CFS)  (F12.0)            0.
91 B2/U       HEIGHT TO TOP OF CONSERVATION POOL (FT) . . . . . . . . . .  (F12.1)          41.0
92 B2/U       CUMULATIVE STORAGE AT TOP OF CONSERVATION POOL (AC FT) . . .  (F12.0)            0.
93 B2/U       SURFACE AREA AT TOP OF CONSERVATION POOL (AC) . . . . . . . .  (F12.0)            0.
94 B2/U       MAXIMUM OUTFLOW CAPACITY AT TOP OF CONSERVATION POOL (CFS) .  (F12.0)            0.
95 B2/U       HEIGHT TO BOTTOM OF POWER POOL (FT) . . . . . . . . . . . . .  (F12.1)           0.
96 B2/U       CUMULATIVE STORAGE AT BOTTOM OF POWER POOL (AC FT) . . . . .  (F12.0)            0.
97 B2/U       SURFACE AREA AT BOTTOM OF POWER POOL (AC) . . . . . . . . . .  (F12.0)            0.
98 B2/U       MAXIMUM OUTFLOW CAPACITY AT BOTTOM OF POWER POOL (CFS) . . .  (F12.0)            0.
99 B2/U       HEIGHT TO TOP OF INACTIVE POOL (FT) . . . . . . . . . . . . .  (F12.1)           0.
100 B2/U      CUMULATIVE STORAGE AT TOP OF INACTIVE POOL (AC FT) . . . . .  (F12.0)            0.
101 B2/U      SURFACE AREA AT TOP OF INACTIVE POOL (AC) . . . . . . . . . .  (F12.0)            0.
102 B2/U      MAXIMUM OUTFLOW CAPACITY AT TOP OF INACTIVE POOL (CFS) . . .  (F12.0)            0.
103 F1 B2/U   HYDRAULIC HEIGHT OF DAM (FT) =210= . . . . . . . . . . . . .  (F12.1)          40.0
104 01 B2/U   MAXIMUM STORAGE (AC FT) =220= . . . . . . . . . . . . . . . .  (F12.0)          4500.
105 F1 B2/U   NORMAL NET POWER HEAD (FT) =250= . . . . . . . . . . . . . .  (F12.1)          30.0
106=113       DISCHARGE (CFS) VS HEIGHT (FT) RELATIONSHIP FOR TAILWATER
      P2 B2/U DISCHARGE(106)      0.(108)    5000.(110)   10000.(112)  15000.   (F8.0)
      P2 B2/U HEIGHT    (107)     7.0(109)      9.0(111)     16.5(113)     18.0   (F8.1)
114=125       MONTHLY PLANT FACTORS
      B2/U M  JAN=  0.  FEB=  0.  MAR=  0.  APR=  0.  MAY=  0.  JUN=  0.       (F6.2)
      B2/U M  JUL=  0.  AUG=  0.  SEP=  0.  OCT=  0.  NOV=  0.  DEC=  0.       (F6.2)

              FORM2 - ILMNCC0202 - HYDROLOGIC CHARACTERISTICS            DATE: 08/19/80

126 B1 B2/U   DRAINAGE AREA (SQ MI) =360= . . . . . . . . . . . . . . . . .  (F12.1)        1906.0
127 B1 B2/U M REPRESENTATIVE GAGE SELECTED =290= . . . . . . . . . . . . .  (F12.0)      5543500.
128 C1 B2/U M AVERAGE ANNUAL INFLOW (CFS) =300= . . . . . . . . . . . . . .  (F12.1)       =1966.1
129=140       NET LAKE EVAPORATION (INCHES)
      B2/U M  JAN(129)  0.    FEB(130)  0.    MAR(131)  0.    APR(132)  0.      (F6.2)
      B2/U M  MAY(133)  0.    JUN(134)  0.    JUL(135)  0.    AUG(136)  0.      (F6.2)
      B2/U M  SEP(137)  0.    OCT(138)  0.    NOV(139)  0.    DEC(140)  0.      (F6.2)
141 B2/U      AVERAGE ANNUAL UPSTREAM DIVERSION (CFS) . . . . . . . . . . .  (F12.1)  000000000000
142 B2/U      PURPOSE OF DIVERSION . . . . . . . . . . . . . . . . . . . . .   (A10)
143           DOWNSTREAM CHANNEL CAPACITY (CFS) . . . . . . . . . . . . . .  (F12.1)  000000000000
144           RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
145           RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
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Figure 5–2 (Continued)

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FORM2 - ILMNCC0202 - OTHER PERTINENT DATA                    DATE: 04/15/80

146 C2/U        PRIOR STUDIES - COMMENT  . . . . . . . . . . . . . . . . . . . .   (5A10)

147 R1-R2/U     KNOWN POTENTIAL CONSTRAINTS -460-  . . . . . . . . . . . . . . .     (A3)
148 C1 C2/U     COMMENT -470-  . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)  FERC

149 C1 C2/U     GENERAL COMMENTS -480- . . . . . . . . . . . . . . . . . . . . .   (5A10)  GROSS STATIC HEAD 34 FT.

150 C1 02/U     GENERAL COMMENTS -490- . . . . . . . . . . . . . . . . . . . . .   (5A10)  ANNUAL PLANT FACTOR 61

151 C1 02/U     GENERAL COMMENTS -500- . . . . . . . . . . . . . . . . . . . . .   (5A10)  DATUM EQ 497.0 NGVD

152 D2/W        KNOWN SIGNIFICANT ADVERSE ENVIRONMENTAL IMPACTS  . . . . . . . .     (A3)
153 02/U        COMMENT  . . . . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)

154 02/U        KNOWN PROJECT PROPONENTS . . . . . . . . . . . . . . . . . . . .     (A3)
155 02/U        COMMENT  . . . . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)

156 02/U        KNOWN PROJECT OPPONENTS  . . . . . . . . . . . . . . . . . . . .     (A3)
157 02/U        COMMENT  . . . . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)

158 02/U        KNOWN OR PROJECTED COMPETITIVE USES OF WATER . . . . . . . . . .     (A3)
159 02/U        COMMENT  . . . . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)

160 C2/U        MAP REFERENCE  . . . . . . . . . . . . . . . . . . . . . . . . .   (5A10)  JOLIET 7.5 MIN

161 02/U        ADDITIONAL VALUE 1 -620- . . . . . . . . . . . . . . . . . . . .  (F12.1)           0.
162 02/U        ADDITIONAL VALUE 2 -630- . . . . . . . . . . . . . . . . . . . .  (F12.1)           0.
163 02/U        ADDITIONAL VALUE 3 -640- . . . . . . . . . . . . . . . . . . . .  (F12.1)           0.
164 02/U        ADDITIONAL VALUE 4 -650- . . . . . . . . . . . . . . . . . . . .  (F12.1)           0.
165 02/U        ADDITIONAL VALUE 5 -660- . . . . . . . . . . . . . . . . . . . .  (F12.1)           0.

FORM2 - ILMNCC0202 - FINANCIAL DATA SUMMARY                  DATE: 04/15/80

166-197                                                    FIELD        MACHINE
                                                         ESTIMATE      ESTIMATE
     E2/U--E2/W TOTAL FIRST COST ($1000)          (166)       0.(182)     6518.   (F9.0)
     E2/U--E2/W CONTINGENCIES                     (167)       0.(183)  1628479.   (F9.0)
     E2/U--E2/W ENGINEERING AND OVERHEAD          (168)       0.(184)  1424919.   (F9.0)
     E2/U--E2/W INTEREST DURING CONSTRUCTION      (169)       0.(185)   657753.   (F9.0)
     E2/U--E2/W TOTAL INVESTMENT ($1000)          (170)       0.(186)    10225.   (F9.0)
     E2/U--E2/W ANNUAL INTEREST AND AMORTIZATION  (171)       0.(187)   703885.   (F9.0)
     E2/U--E2/W ANNUAL O, M, AND R                (172)       0.(188)   275577.   (F9.0)
     E2/U--E2/W ANNUAL PUMPING COST               (173)       0.(189)        0.   (F9.0)
     E2/U--E2/W TOTAL ANNUAL COST                 (174)       0.(190)   979462.   (F9.0)
     E2/U--E2/W INTEREST RATE (PERCENT X 1000)    (175)       0.(191)     6875.   (F9.0)
     E2/U--E2/W PRICE LEVEL (YEAR)                (176)       0.(192)        0.   (F9.0)
     E2/U--E2/W ANNUAL POWER BENEFITS ($1000)     (177)       0.(193)     1722.   (F9.0)
     E2/U--E2/W OTHER ANNUAL BENEFITS ($1000)     (178)       0.(194)        0.   (F9.0)
     E2/U--E2/W TOTAL ANNUAL BENEFITS ($1000)     (179)       0.(195)     1722.   (F9.0)
     E2/U--E2/W BENEFIT-TO-COST RATIO X 100       (180)       0.(196)      176.   (F9.0)
     E2/U--E2/W AVERAGE COST OF ENERGY ($/MWH)    (181)       0.(197)       28.   (F9.0)
198             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
199             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
200             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
201             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
202             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
203             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
204             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
205             RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.

FORM2 - ILMNCC0202 - DETAILS OF FIELD ESTIMATE               DATE: 04/15/80
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Figure 5—2 (Continued)

206 F2/W	LANDS AND DAMAGES ($1000)	(F12.2)	0.
207 F2/U	RELOCATIONS ($1000)	(F12.2)	0.
208 F2/W	RESERVOIRS ($1000)	(F12.2)	0.
209 F2/W	DAM ($1000)	(F12.2)	0.
210 F2/U	AUXILIARY DAM ($1000)	(F12.2)	0.
211 F2/W	POWER INTAKE ($1000)	(F12.2)	0.
212 F2/W	POWERPLANT (INCLUDING SWITCHYARD) ($1000)	(F12.2)	0.
213 F2/U	ROADS, RAILROADS, AND BRIDGES ($1000)	(F12.2)	0.
214 F2/U	RECREATION FACILITIES ($1000)	(F12.2)	0.
215 F2/U	TRANSMISSION FACILITIES ($1000)	(F12.2)	0.
~~216 F2/U~~	~~BUILDINGS, GROUNDS, AND UTILITIES ($1000) . . . .~~	~~(F12.2)~~	~~0.~~
217 F2/U	PERMANENT OPERATING EQUIPMENT ($1000)	(F12.2)	0.
218 R2/U W	POTENTIAL CAPACITY (KW)	(F12.2)	0.
219 R2/U W	ANNUAL ENERGY PRODUCTION (MWH)	(F12.2)	0.
220 R2/U W	ANNUAL PUMPING ENERGY (MWH)	(F12.2)	0.
221 R2/U W	DEPENDABLE CAPACITY VALUE ($/KW-YR)	(F12.2)	0.
~~222 R2/U W~~	~~INTERRUPTIBLE CAPACITY VALUE ($/KW-YR) . . . .~~	~~(F12.2)~~	~~0.~~
223 R2/U W	ENERGY PRODUCTION VALUE ($/MWH)	(F12.2)	0.
224 R2/U W	PUMPING ENERGY COST ($/MWH)	(F12.2)	0.
225 O2/U	COMMENT - ALTERNATIVE ASSUMED	(9A10)	
226 R2/U	COST ALLOCATION ON WHICH ABOVE COSTS ARE BASED (EX. MSCS) .	(A10)	
~~227 R2/U W~~	~~LOCAL OR REMOTE OPERATION (TURBINE TYPE - 2ND CHARACTER) . . .~~	~~(A10)~~	
228	RESERVED FOR FUTURE USE	(A10)	
229	RESERVED FOR FUTURE USE	(A10)	
230	RESERVED FOR FUTURE USE	(A10)	
231 R1 R2/U W	CONVENTIONAL CAPACITY - EXISTING (KW) -320-	(F12.2)	0.
232 R2/U W	CONVENTIONAL CAPACITY - NEW POTENTIAL (KW)	(F12.2)	0.
~~233 R1 R2/U W~~	~~CONVENTIONAL CAPACITY - TOTAL (KW) -360- . . . .~~	~~(F12.2)~~	~~0.~~
234 R2/U	REVERSIBLE CAPACITY - EXISTING (KW)	(F12.2)	0.
235 R2/U W	REVERSIBLE CAPACITY - NEW POTENTIAL (KW)	(F12.2)	0.
236 R2/W	REVERSIBLE CAPACITY - TOTAL (KW)	(F12.2)	0.
237 R2/W	TOTAL PLANT CAPACITY - EXISTING (KW)	(F12.2)	0.
238 R2/U W	NUMBER OF UNITS FOR ITEM 237	(F12.2)	0.
~~239 R1 R2/U W~~	~~AVERAGE ANNUAL ENERGY - EXISTING (MWH) -330- . . . .~~	~~(F12.2)~~	~~0.~~
240 R2/U W	AVERAGE ANNUAL PLANT FACTOR (PERCENT)	(F12.2)	0.
241 O2/U	COMMENT	(5A10)	
242 O2/U	COMMENT	(5A10)	
~~243 R2/U W~~	~~TOTAL PLANT CAPACITY - NEW POTENTIAL (KW) . . . .~~	~~(F12.2)~~	~~0.~~
244 R2/U W	NUMBER OF UNITS FOR ITEM 243	(F12.2)	0.
245 R2/W	TOTAL PLANT CAPACITY - TOTAL (KW)	(F12.2)	0.
246 R2/U W	NUMBER OF UNITS FOR ITEM 245	(F12.2)	0.
247 R1 R2/U W	AVERAGE ANNUAL ENERGY - TOTAL (MWH) -370-	(F12.2)	28827.31
248 R2/U W	AVERAGE ANNUAL PLANT FACTOR	(F12.2)	0.
~~249 O2/U~~	~~COMMENT . . . .~~	~~(5A10)~~	
250 R2/U W	DEPENDABLE CAPACITY - EXISTING (KW)	(F12.2)	0.
251 R2/U W	DEPENDABLE CAPACITY - TOTAL (KW)	(F12.2)	0.
252 R2/U	PUMPING ENERGY REQUIRED - EXISTING (MWH)	(F12.2)	0.
253 R2/W	PUMPING ENERGY REQUIRED - TOTAL (MWH)	(F12.2)	0.
~~254 O2/U~~	~~COMMENT . . . .~~	~~(5A10)~~	
255	ANNUAL FIRM ENERGY - EXISTING (MWH)	(F12.2)	************
256	ANNUAL FIRM ENERGY - TOTAL (MWH)	(F12.2)	************
257	RESERVED FOR FUTURE USE	(A10)	
258	RESERVED FOR FUTURE USE	(A10)	
~~259~~	~~RESERVED FOR FUTURE USE . . . .~~	~~(A10)~~	
260	RESERVED FOR FUTURE USE	(A10)	

PCRM2 - ILMNCC0202 - SOURCE BY TYPE OF NEW CAPACITY AND ENERGY DATE: 04/15/80

261 F2/U	ELECTRIC TURBINES AND GENERATORS (KW)	(F12.0)	0.

Figure 5–2 (Continued)

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262 C2/U    UPGRADING TURBINES AND GENERATORS (MWH) . . . . . . . . . . .   (F12.0)           0.
263 C2/U    REALLOCATION OF STORAGE (KW) . . . . . . . . . . . . . . . . .  (F12.0)           0.
264 C2/U    REALLOCATION OF STORAGE (MWH) . . . . . . . . . . . . . . . .   (F12.0)           0.
265 C2/U    OPERATIONAL CHANGES (KW) . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
266 C2/U    OPERATIONAL CHANGES (MWH) . . . . . . . . . . . . . . . . . .   (F12.0)           0.
267 C2/U    ADDITIONAL GENERATING SETS (KW) . . . . . . . . . . . . . . .   (F12.0)           0.
268 C2/U    ADDITIONAL GENERATING SETS (MWH) . . . . . . . . . . . . . . .  (F12.0)           0.
269 C2/U    OTHER (KW) . . . . . . . . . . . . . . . . . . . . . . . . . .  (F12.0)           0.
270 C2/U    OTHER (MWH) . . . . . . . . . . . . . . . . . . . . . . . . .   (F12.0)           0.
271 C2/U    COMMENT ON OTHER . . . . . . . . . . . . . . . . . . . . . . .  65A10)

272         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
273         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
274         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)
275         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . .   (A10)

              FORM2 - ILMNCC0202 - POWER DATA -- MACHINE RESULTS --          DATE:  04/15/80

276         LATEST ESTIMATE OF DEPENDABLE CAPACITY FROM SEQ. ANALYSIS .     (F12.0)           0.
277         LATEST ESTIMATE OF ANNUAL FIRM ENERGY FROM SEQ. ANALYSIS . .    (F12.0)           0.
278         OPTIMUM PERCENT EXCEEDENCE FROM FLOW-DURATION ANALYSIS . . .    (F12.4)       .0149
279         OPTIMUM PERCENT EXCEEDENCE FROM SEQUENTIAL ANALYSIS . . . .     (F12.4)       0.
280         ITEMS 290 THRU 319 ARE BASED UPON (SEQ) OR (FLD) ANALYSIS .     (A3)   FLD
281         LATEST ESTIMATE OF AVERAGE ANNUAL ENERGY FROM SEQ. ANALYSIS     (F12.2)           0.
282         AVERAGE ANNUAL SPILLAGE (CFS) FROM FLOW-DURATION ANALYSIS .     (F12.2)       35.64
283         AVERAGE ANNUAL AVAILABLE POWER FLOW (CFS) . . . . . . . . .     (F12.2)     1930.45
284         AVERAGE ANNUAL ENERGY ADJUSTMENT FACTOR  .(0.0 TO 2.0) . . .    (F12.2)          0.
285         LATEST ESTIMATE OF POWER HEAD FROM SEQ. ANALYSIS . . . . . .    (F12.2)          0.
286         LATEST ESTIMATE OF AVERAGE ANNUAL SPILL FROM SEQ. ANALYSIS .    (F12.2)  ************
287         AVE. ANNUAL ENERGY FOR EXISTING CAPACITY (FLOW-DURATION) . .    (F12.2)  ************
288         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . .     (F12.2)  ************
289         RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . .     (F12.2)          0.
            ... TOTAL POTENTIAL RESULTS ... -700 THRU 709-
290         CAPACITY (KW) . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)    14157.02
291         AVERAGE ANNUAL ENERGY (MWH) . . . . . . . . . . . . . . . .     (F12.2)    40364.12
292         ANNUAL PLANT FACTOR . . . . . . . . . . . . . . . . . . . .     (F12.2)         .33
293         DEPENDABLE CAPACITY BENEFIT ($/KW-YR) . . . . . . . . . . .     (F12.2)       70.00
294         AVERAGE ANNUAL ENERGY BENEFIT ($/MWH-YR) . . . . . . . . . .    (F12.2)       28.44
295         ANNUAL CAPACITY BENEFIT ($/YR) . . . . . . . . . . . . . . .    (F12.2)   574060.85
296         ANNUAL ENERGY BENEFIT ($/YR) . . . . . . . . . . . . . . . .    (F12.2)  1148013.21
297         TOTAL ANNUAL BENEFIT ($/YR) . . . . . . . . . . . . . . . .     (F12.2)  1722074.06
298         TOTAL ANNUAL COST ($/YR) . . . . . . . . . . . . . . . . . .    (F12.2)   979461.93
299         B/C RATIO . . . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)        1.76
            ... EXISTING CAPACITY RESULTS ... -320 THRU 330-
300         CAPACITY (KW) . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)          0.
301         AVERAGE ANNUAL ENERGY (MWH) . . . . . . . . . . . . . . . .     (F12.2)          0.
302         ANNUAL PLANT FACTOR . . . . . . . . . . . . . . . . . . . .     (F12.2)          0.
303         DEPENDABLE CAPACITY BENEFIT ($/KW-YR) . . . . . . . . . . .     (F12.2)          0.
304         AVERAGE ANNUAL ENERGY BENEFIT ($/MWH-YR) . . . . . . . . . .    (F12.2)          0.
305         ANNUAL CAPACITY BENEFIT ($/YR) . . . . . . . . . . . . . . .    (F12.2)          0.
306         ANNUAL ENERGY BENEFIT ($/YR) . . . . . . . . . . . . . . . .    (F12.2)          0.
307         TOTAL ANNUAL BENEFIT ($/YR) . . . . . . . . . . . . . . . .     (F12.2)          0.
308         TOTAL ANNUAL COST ($/YR) . . . . . . . . . . . . . . . . . .    (F12.2)          0.
309         B/C RATIO . . . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)          0.
            ... INCREMENTAL CAPACITY RESULTS ... -710 THRU 719-
310         CAPACITY (KW) . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)    14157.02
311         AVERAGE ANNUAL ENERGY (MWH) . . . . . . . . . . . . . . . .     (F12.2)    40364.12
312         ANNUAL PLANT FACTOR . . . . . . . . . . . . . . . . . . . .     (F12.2)         .33
313         DEPENDABLE CAPACITY BENEFIT ($/KW-YR) . . . . . . . . . . .     (F12.2)       70.00
314         AVERAGE ANNUAL ENERGY BENEFIT ($/MWH-YR) . . . . . . . . . .    (F12.2)       28.44
315         ANNUAL CAPACITY BENEFIT ($/YR) . . . . . . . . . . . . . . .    (F12.2)   574060.85
316         ANNUAL ENERGY BENEFIT ($/YR) . . . . . . . . . . . . . . . .    (F12.2)  1148013.21
317         TOTAL ANNUAL BENEFIT ($/YR) . . . . . . . . . . . . . . . .     (F12.2)  1722074.06
318         TOTAL ANNUAL COST ($/YR) . . . . . . . . . . . . . . . . . .    (F12.2)   979461.93
319         B/C RATIO . . . . . . . . . . . . . . . . . . . . . . . . .     (F12.2)        1.76
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Figure 5–2 (Continued)

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320-439   MACHINE RESULTS FROM FLOW-DURATION ANALYSIS
440-505   MACHINE RESULTS FROM SEQUENTIAL FLOW ANALYSIS
506       NUMBER OF UNITS . . . . . . . . . . . . . . . . . . . . . . . . . .  (F12.0)        2.
507       SIZE OF UNITS (KW) . . . . . . . . . . . . . . . . . . . . . . . . .  (F12.0)        0.
508       TYPE OF UNITS . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

509-569   MACHINE RESULTS FROM SEQUENTIAL FLOW ANALYSIS

               FORM2 - ILMNCC0202 - ENVIRONMENTAL IMPACTS                  DATE: 04/15/80

570       NATIONAL/STATE PARK/LANDS ADVERSELY IMPACTED (AC) . . . . . . .  (F12.2)  ************
571       NATIONAL/STATE PARK/LANDS ENHANCED (AC) . . . . . . . . . . . .  (F12.2)  ************
572       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

573       NATIONAL/STATE WILD AND SCENIC RIVERS DEGRADED (MI) . . . .  (F12.2)  ************
574       NATIONAL/STATE WILD AND SCENIC RIVERS ENHANCED (MI) . . . .  (F12.2)  ************
575       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

576       POTENTIAL WILD AND SCENIC RIVERS DEGRADED (MI) . . . . . . . .  (F12.2)  ************
577       POTENTIAL WILD AND SCENIC RIVERS ENHANCED (MI) . . . . . . . .  (F12.2)  ************
578       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

579       RECREATION LAKES/RESERVOIRS ADVERSELY IMPACTED (AC) . . . . .  (F12.2)  ************
580       RECREATION LAKES/RESERVOIRS ENHANCED (AC) . . . . . . . . . . .  (F12.2)  ************
581       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

582       WILDERNESS,PRIMITIVE AND/OR NATURAL,ADVERSELY IMPACTED (AC)  (F12.2)  ************
583       WILDERNESS,PRIMITIVE AND/OR NATURAL,ENHANCED (AC) . . . . . .  (F12.2)  ************
584       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

585       ESTUARINE AND WETLAND AREAS ADVERSELY IMPACTED (AC) . . . . .  (F12.2)  ************
586       ESTUARINE AND WETLAND AREAS ENHANCED (AC) . . . . . . . . . . .  (F12.2)  ************
587       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

588       CULTURAL RESOURCE SITES ADVERSELY IMPACTED (NUMBER) . . . . .  (F12.2)  ************
589       CULTURAL RESOURCE SITES PRESERVED (NUMBER) . . . . . . . . . .  (F12.2)  ************
590       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

591       CRITICAL/IMPORTANT WILDLIFE HABITAT ADVERSELY IMPACTED (AC)  (F12.2)  ************
592       CRITICAL/IMPORTANT WILDLIFE HABITAT ENHANCED (AC) . . . . . .  (F12.2)  ************
593       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

594       FISHERY HABITAT ADVERSELY IMPACTED (AC) . . . . . . . . . . . .  (F12.2)  ************
595       FISHERY HABITAT ENHANCED (AC) . . . . . . . . . . . . . . . . .  (F12.2)  ************
596       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

597       FISHERY HABITAT ADVERSELY IMPACTED (STREAM MILE) . . . . . . .  (F12.2)  ************
598       FISHERY HABITAT ENHANCED (STREAM MILE) . . . . . . . . . . . .  (F12.2)  ************
599       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

600       ENDANGERED SPECIES ADVERSELY IMPACTED (NUMBER) . . . . . . . .  (F12.2)  ************
601       ENDANGERED SPECIES ENHANCED (NUMBER) . . . . . . . . . . . . .  (F12.2)  ************
602       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

603       WATER QUALITY ADVERSELY IMPACTED . . . . . . . . . . . . . . . .  (A3)
604       WATER QUALITY ENHANCED . . . . . . . . . . . . . . . . . . . . .  (A3)
605       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

606       OTHER ADVERSE IMPACTS . . . . . . . . . . . . . . . . . . . . . .  (A3)
607       OTHER ENHANCEMENTS . . . . . . . . . . . . . . . . . . . . . . .  (A3)
608       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

609       DELETE FROM ACTIVE INVENTORY . . . . . . . . . . . . . . . . . .  (A3)
610       COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)
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Figure 5–2 (Continued)

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611    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
612    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
613    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
614    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
615    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
616    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
617    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
618    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
619    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)

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620    PERSONS RELOCATED (NUMBER) . . . . . . . . . . . . . . . . . . .  (F12.2)           0.
621    TOWNS RELOCATED (NUMBER) . . . . . . . . . . . . . . . . . . . .  (F12.2)           0.
622    BUSINESSES RELOCATED (NUMBER) . . . . . . . . . . . . . . . . .   (F12.2)  ************
623    HIGHWAYS AND RAILROADS RELOCATED (MI) . . . . . . . . . . . . .   (F12.2)  ************
624    HIGHWAY AND RAILROAD BRIDGES RELOCATED (NUMBER) . . . . . . . .   (F12.2)  ************
625    NAVIGATION ADVERSELY IMPACTED (MI) . . . . . . . . . . . . . . .  (F12.2)  ************
626    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

627    NAVIGATION ENHANCED (MI) . . . . . . . . . . . . . . . . . . . .  (F12.2)  ************
628    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

629    FARM LAND INUNDATED (AC) . . . . . . . . . . . . . . . . . . . .  (F12.2)  ************
630    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

631    DELETE FROM ACTIVE INVENTORY . . . . . . . . . . . . . . . . . .    (A3)
632    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

633    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
634    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
635    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
636    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
637    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
638    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)
639    RESERVED FOR FUTURE USE . . . . . . . . . . . . . . . . . . . . .   (A10)

           FORM2 - ILMNCC0202 - PROJECT ACCEPTABILITY             DATE: 04/15/80

640    POLITICAL FACTORS SUPPORTING AUTHORIZATION . . . . . . . . . . .    (A3)
641    POLITICAL FACTORS OPPOSING AUTHORIZATION . . . . . . . . . . . .    (A3)
642    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

643    OTHER FEDERAL AND STATE AGENCY OPPOSITION . . . . . . . . . . .     (A3)
644    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

645    LOCAL PUBLIC SUPPORT . . . . . . . . . . . . . . . . . . . . . .    (A3)
646    LOCAL PUBLIC OPPOSITION . . . . . . . . . . . . . . . . . . . . .   (A3)
647    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

648    ENVIRONMENTAL GROUP SUPPORT . . . . . . . . . . . . . . . . . . .   (A3)
649    ENVIRONMENTAL GROUP OPPOSITION . . . . . . . . . . . . . . . . .    (A3)
650    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

651    OTHER SOCIAL GROUP SUPPORT . . . . . . . . . . . . . . . . . . .    (A3)
652    OTHER SOCIAL GROUP OPPOSITION . . . . . . . . . . . . . . . . . .   (A3)
653    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

654    UTILITY INTEREST GROUP SUPPORT . . . . . . . . . . . . . . . . .    (A3)
655    UTILITY INTEREST GROUP OPPOSITION . . . . . . . . . . . . . . . .   (A3)
656    COMMENT . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)

657    GENERAL COMMENT . . . . . . . . . . . . . . . . . . . . . . . . .  (5A10)
```

Figure 5–2 (Continued)

```
658        DELETE FROM ACTIVE INVENTORY . . . . . . . . . . . . . . . . .        (A3)
659        COMMENT  . . . . . . . . . . . . . . . . . . . . . . . . . . .      (5A10)

660        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
661        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
662        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
663        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
664        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
665        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
666        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
667        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
668        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)
669        RESERVED FOR FUTURE USE  . . . . . . . . . . . . . . . . . . .       (A10)

                 FORM2 - ILPACC0202 - MARKETABILITY                      DATE:  04/15/80

670        AVERAGE ANNUAL POWER REPAYMENT REQUIRED ($1000)  . . . . . .     (F12.2)           0.
671        REPAYMENT RATE REQUIRED ($/KW-YR)  . . . . . . . . . . . . .     (F12.2)           0.
672        REPAYMENT RATE REQUIRED ($/MWH)  . . . . . . . . . . . . . .     (F12.2)           0.
673        DEPENDABLE CAPACITY VALLE ($/KW-YR)  . . . . . . . . . . . .     (F12.2)      -70.00
674        INTERRUPTIBLE CAPACITY VALUE ($/KW-YR) . . . . . . . . . . .     (F12.2)      -35.00
675        FIRM ENERGY VALUE ($/MWH)  . . . . . . . . . . . . . . . . .     (F12.2)  ************
676        SECONDARY ENERGY VALUE ($/MWH) . . . . . . . . . . . . . . .     (F12.2)  ************
677        GENERAL COMMENT  . . . . . . . . . . . . . . . . . . . . . .      (5A10)

678        GENERAL COMMENT  . . . . . . . . . . . . . . . . . . . . . .       (A10)
679        DELETE FROM ACTIVE INVENTORY . . . . . . . . . . . . . . . .       (A10)
680        COMMENT ON DELETION FROM ACTIVE INVENTORY  . . . . . . . . .       (A10)

COMMAND AND CONSTRAINTS - END
```

Figure 5–2 (Concluded)

5.4 1st SCREENING, SITE EVALUATION - STAGE 3

The purpose of this activity was to screen active sites in the computer base on the basis of more detailed and refined economic information. This activity encompassed a more detailed analysis of power related project costs and benefits using computer routines or available cost data. The result was an evaluation of projects based only on the economics of power development. The economic data thus generated could be used to delete less desirable projects from the active inventory, solely on the basis of estimated benefits and costs.

HEC provided technical support and conducted the screening by computer. Each Division was responsible for accessing the computer inventory file and withdrawing the active and inactive site lists for its Districts. Each District reviewed the results of the screening to insure that the lists were consistent and accurate. NCD consolidated the lists after review by its Districts and updated the inventory file.

After each District added Form 2 data into the computer data base, the HEC performed another screening and economic analysis by computer. To pass this screening, sites had to meet the following criteria:

a. 1 megawatt output;

b. 1.0 benefit-cost ratio (developed sites); and,

c. 0.7 benefit-cost ratio (undeveloped sites).

The Districts reviewed the results of the screening and revised the inactive and active lists in the data base.

5.5 SECOND DATA COLLECTION - STAGE 3

The purpose of this activity was to collect additional Form 2 data on environmental, social, and institutional aspects of sites passing the stage 3 first screening. The information gathered during this activity was the basis for the stage 3 second screening. Although data collection was the major task of this activity, each District made an implicit evaluation of each site with respect to overriding environmental, institutional, or social factors.

NCD provided the data resulting from the stage 3 first screening to its Districts. The District offices filled out the necessary Form 2 data items.

Those sites meeting the stage 3 first screening criteria of 1-megawatt continuous output and 1.0 benefit-cost ratio (developed sites) or 0.7 benefit-cost ratio (undeveloped sites) were given to each District's Environmental Resources Branch for additional data preparation. Available data relating to environmental, social, and project acceptability were compiled and entered in the computer data base Form 2 format by each District.

5.6 SECOND SCREENING SITE EVALUATION- STAGE 3

The purpose of this activity was to evaluate those potential sites passing the stage 3 first screening and to remove from the active file those projects having overriding adverse noneconomic impacts. Each site was evaluated according to environmental, social, and institutional characteristics. Those sites which were considered to have overriding adverse noneconomic impacts were removed from active consideration. The principal tasks were to:

1. Use selected environmental, social, and institutional data gathered during the stage 3 second data collection activity to screen sites.

2. Complete Division/District review of the results of the screening for consistency and accuracy in addition to eliminating from further study any additional sites having overriding adverse environmental, social, or institutional impacts.

3. Identify all sites that will undergo detailed evaluation in the regional site identification activity.

The Corps Southwest Division provided a tabulation of the results of the partial screening based on strict "either/or" criteria. HEC provided technical support with the computer listing. NCD was responsible for accessing the computer data base for the results of the partial screening and sending these results to each District for review.

Districts were responsible for reviewing results of the partial screening and conducting the composite evaluation on the basis of all social, economic, and institutional criteria.

The strategies for increasing hydropower production can be described by three broad categories. These categories are based on the different levels of construction activity and environmental impact.

The most significant, in terms of both construction activity and alternations to the existing environment, is the development of new impoundments. This involves major construction activity for building a new dam structure. A backwater pool would be created by impounding an existing free flowing stream and the flooding of terrestrial and wetland habitats. Discharge from the pool would be regulated and can occur either at the dam site or the discharge can be diverted to some point downstream. After passing through the turbines the water is discharged to the stream. Penstocks can be used in order to gain additional increases in hydraulic head. Power transmission lines must be constructed from the powerhouse to a point in the existing transmission network.

Environmental and social impacts were identified which might result from the construction of a new impoundment. The environmental impact categories were derived primarily from the requirements of Section 122 of PL-611, the Rivers and Harbors Act of 1970. Additional impact categories were added which are based on other statutes and executive orders and include archeological/historical features, destruction of wetlands, and threatened and endangered species. Finally, due to the particular significance of hydropower to certain environmental characteristics, the impacts categories such as changes to Pool and Stream and Terrestrial Habitats were added. The impact analysis is in matrix format and presented in Figure 5-3 for new impoundments.

The second category of construction involves the retrofitting of existing dam sites to produce hydropower. This strategy is not as significant in terms of environmental alterations as the creation of new impoundments. Construction activities include dredging and cofferdam installation in the existing pool or dam site, building or rebuilding of a powerhouse, possible alterations to the discharge structure, and the possible construction of penstock diversions and transmission lines. Figure 5-4 presents the impact analysis matrix for this category of construction.

The third construction strategy is to alter the existing powerplant and to increase the generating capability by adding larger or additional equipment at sites which currently generate hydroelectric power. Typically, this strategy would involve the least amount of change to existing environmental conditions. Construction activities range from modifications or replacement of existing turbines to adding turbines and conducting major structural alterations which approach those described in the second category. Figure 5-5 presents the impact analysis matrix for this category of construction.

The impact analysis carried out was strictly qualitative due to the lack of sufficient resources to examine each individual site. Environmental, social and institutional data were collected for all Stage III sites. Among the data collection for each site were some or all of the following items:

Environmental Impacts on national or state park lands; Wild and Scenic Rivers; recreation lakes; primitive or Wilderness areas; fishery habitat; endangered species; and, water quality.

Social: Number of people, towns, and or business relocated; impacts on navigation and amount of farm land flooded; and,

Institutional: Political factors either supporting or opposing project authorization; local, environmental groups, agency support or opposition and utility interest groups support or opposition.

KEY

Magnitude: i = insignificant
m = minor
M = major

Duration: s = short-term
L = long-term

Value: + = mostly beneficial
0 = uncertain/both
- = mostly detrimental

CONSTRUCTION - OPERATION ELEMENTS	Social Effects						Economic Effects								Environmental Effects						
	Noise	Displacement of People	Aesthetic Values	Archeologic/Historic Features	Community Cohesion	Desirable Community Growth	Local Government Finance/Tax Revenues	Local Government Finance/Property Values	Public Facilities	Public Services	Desirable Regional Growth	Employment/Labor Force	Business/Industrial Activity	Displacement of Farms	Pollutional Aspects - Air	Pollutional Aspects - Water	Changes in Pool Habitat	Changes in Stream Habitat	Changes in Terrestrial Habitat	Changes in Wetland Habitat	Threatened & Endangered Species
New Dam Construction	Ms-	mL-	ML-	ML-	ML0	mL+	mL+	mL+	ms0	ms-	ms+	Ms+	Ms+	mL-	ms-	Ms-	ms-	ms-	ms-	ms-	ms-
Flooding of New Impoundments	ms0	ML-	ML0	ML-	ML-	ML-	ML-	ML-	ML-	ML-	mL0	mL0	ML0	ML-	mL+	ML-	ML+	ML-	ML-	ML0	ml-
Construction/Operation of Penstock Diversion[1]	ms-	mL-	mL-	mL-	i	i	mL0	mL0	ms0	ms0	i	ms+	i	i	ms-	mL-	ms0	ML-	ms-	ms-	ms-
Construction of New Power Plant	Ms-	mL-	mL-	mL-	i	i	mL+	mL+	ms0	ms0	ms+	ms+	ms+	i	ms-	ms-	mL0	ms0	mL-	mL-	mL-
Construction of Power Transmission Lines	Ms-	i	ML-	mL-	mL-	i	i	i	i	ms-	i	ms+	ms+	i	ms-	i	i	i	mL0	mL0	mL0
Additional Hydropower Production	mL-	i	i	i	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	i	i	i	i	i

1 This element would sometimes be a feature of new impoundments.

Figure 5—3

UNDEVELOPED SITES

Environmental—Social Impact Analysis Matrix

KEY

Magnitude: i = insignificant
m = minor
M = major

Duration: s = short-term
L = long-term

Value: + = mostly beneficial
0 = uncertain/both
- = mostly detrimental

CONSTRUCTION - OPERATION ELEMENTS	Social Effects: Noise	Displacement of People	Aesthetic Values	Archeologic/Historic Features	Community Cohesion	Desirable Community Growth	Economic Effects: Local Government Finance/Tax Revenues	Local Government Finance/Property Values	Public Facilities	Public Services	Desirable Regional Growth	Employment/Labor Force	Business/Industrial Activity	Displacement of Farms	Environmental Effects: Pollutional Aspects - Air	Pollutional Aspects - Water	Changes in Pool Habitat	Changes in Stream Habitat	Changes in Terrestrial Habitat	Changes in Wetland Habitat	Threatened & Endangered Species
Modifications to Existing Dams	Ms-	mL-	mL0	mL0	i	i	mL+	mL+	ms0	ms-	ms+	ms+	ms+	i	ms-	Ms-	ms-	ms-	i	i	i
Construction/Operation of Penstock Diversion[1]	ms-	mL-	mL-	mL-	i	i	mL0	mL0	ms0	ms0	i	ms+	i	i	ms-	mL-	ms0	ML-	ms-	ms-	ms-
Construction of New Power Plant	Ms-	mL-	mL-	mL-	i	i	mL+	mL+	ms0	ms0	ms+	ms+	ms+	i	ms-	ms-	mL0	ms0	mL-	mL-	mL-
Construction of Power Transmission Lines	Ms-	i	ML-	mL-	mL-	i	i	i	i	ms-	i	ms+	ms+	i	ms-	i	i	i	mL0	mL0	mL0
Changing Stage-Duration of Existing Pool[2]	i	mL-	ML-	mL-	mL0	mL0	mL0	mL0	i	i	i	i	i	mL-	i	i	ML-	mL0	ML-	ML0	ML0
Dredging and Dredged Material Disposal[1]	ms-	i	ms-	ms-	i	i	i	i	i	i	i	ms+	i	i	i	Ms-	ML0	ms-	ms-	ms0	i
Lowering Water Outlet Levels[1]	i	i	Ms-	i	i	i	i	i	i	i	i	i	i	i	i	Ms-	Ms-	Ms0	i	Ms0	i
Additional Hydropower Production	mL-	i	i	i	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	i	i	i	i	i

1 This element would sometimes be a feature when hydropower is developed at an existing site.

2. The analysis of hydropower is based upon the assumption that there will not be any change in pool elevations. However, implementation studies for individual sites may consider changes in pool elevation/regulation to optimize benefits.

Figure 5-4

EXISTING SITES WITHOUT HYDROPOWER

Environmental-Social Impact Analysis Matrix

KEY

Magnitude: i = insignificant
m = minor
M = major

Duration: s = short-term
L = long-term

Value: + = mostly beneficial
0 = uncertain/both
- = mostly detrimental

CONSTRUCTION - OPERATION ELEMENTS	Social Effects: Noise	Displacement of People	Aesthetic Values	Archeologic/Historic Features	Community Cohesion	Desirable Community Growth	Economic Effects: Local Government Finance/Tax Revenues	Local Government Finance/Property Values	Public Facilities	Public Services	Desirable Regional Growth	Employment/Labor Force	Business/Industrial Activity	Displacement of Farms	Environmental Effects: Pollutional Aspects - Air	Pollutional Aspects - Water	Changes in Pool Habitat	Changes in Stream Habitat	Changes in Terrestrial Habitat	Changes in Wetland Habitat	Threatened & Endangered Species
Modifications to Existing Dams[1]	Ms-	mL-	mL0	mL0	i	i	mL+	mL+	ms0	ms-	ms+	ms+	ms+	i	ms-	Ms-	ms-	ms-	i	i	i
Construction/Operation of Penstock Diversion[1]	ms-	mL-	mL-	mL-	i	i	mL0	mL0	ms0	ms0	i	ms+	i	i	ms-	mL-	ms0	ML-	ms-	ms-	ms-
Turbine Replacement/Addition[2]	ms-	i	i	i	i	i	mL+	i	i	i	i	i	i	i	i	i	i	i	i	i	i
Changing Stage-Duration of Existing Pool[3]	i	mL-	ML-	mL-	mL0	mL0	mL0	mL0	i	i	i	i	i	mL-	i	i	ML-	mL0	ML-	ML0	ML0
Dredging and Dredged Material Disposal[1]	ms-	i	ms-	ms-	i	i	i	i	i	i	i	ms+	i	i	i	Ms-	ML0	ms-	ms-	ms0	i
Lowering Water Outlet Levels[1]	i	i	Ms-	i	i	i	i	i	i	i	i	i	i	i	i	Ms-	Ms-	Ms0	i	Ms0	i
Additional Hydropower Production	mL-	i	i	i	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	mL+	i	i	i	i	i

1 This element would sometimes be a feature when additional hydropower is added to an existing facility.

2 This element would usually be a feature when additional hydropower is added to an existing facility.

3 This analysis of hydropower is based upon the assumption that there will not be any change in pool elevations. However, implementation studies for individual sites may consider changes in pool regulation/elevation to optimize benefits.

Figure 5–5

EXISTING SITES WITH HYDROPOWER

Environmental–Social Impact Analysis Matrix

Chapter 6
PUBLIC INVOLVEMENT

6.1 ROLE OF PUBLIC INVOLVEMENT

The need for cooperation and coordination between all Federal, state and local agencies during a study of such magnitude as the NHS is apparent. The interests of affected states, utilities, local communities, and individuals are of significant concern and must be recognized and considered. The role of public involvement in the study is to:

- provide a means of informing the public of the current status of NHS;
- answer questions and clarify key issues involved in the study; and,
- provide a mechanism for public input into the study.

This has been accomplished by public meetings, periodic news releases and talks before civic groups. Intermittently throughout the NHS, the study coordinator was quoted in local and regional newspapers stating the current status of the study and providing site specific information. Several radio interviews were also presented. Two required public meetings were held, one in Minneapolis, Minnesota (a combined meeting for both MAIN and MARCA Reliability Councils) and a second meeting in Chicago, Illinois.

6.2 PUBLIC MEETINGS

Public Meeting March 1980

On 4 March 1980, a Regional Public Meeting was held in Minneapolis, Minnesota. The purpose of the meeting was to provide information relative to the purposes and progress of the study and to seek public comments and identifiable concerns regarding the study in MAIN and the MARCA regions. Of the 104 people in attendance, nine verbal statements were presented and three agencies submitted written statements.

- The Director of the Saint Anthony Falls Hydraulic Laboratory at the University of Minnesota commended the Corps of Engineers for taking the initiative in studying the potential resources of hydropower. He also expressed the need for an active on-going research program in regard to hydropower and its potential.
- The Assistant Executive Director of Midwest Electric Consumers Association expressed concern over potential policies involving

the marketing of power from Federal hydropower plants and how they would be treated in the National Hydropower Study.

- The Assistant Executive Director of Midwest Electric Consumers Association also expressed concern on the narrowing of a large number of sites to such a small number.

- In a written statement, the State Water Survey Division of the Illinois Institute of Natural Resources, expressed concern on the trade-offs between hydropower at navigation dams and the dams' reaeration capabilities.

Subsequent Input

The 4 March 1980 public meeting generated a daily average of 5 to 10 telephone calls or personal visits to the St. Paul District for several days afterward.

Results

The telephone and personal contacts provided some changes and additions to the study data base. However, most of the contacts requested specific site data from the study data base.

Public Meeting August 1980

On 14 August 1980, a Regional Public Meeting was held in Chicago, Illinois. The purpose of the meeting was to present preliminary study results for MAIN and to solicit public comment of them. Of the 54 people in attendance, three presented verbal statements which are summarized below:

- The Mayor of the City of Breese (Illinois) stated that they have a municipal power plant and that they are attending the meeting to gather data for their own use.

- A representative of the Wisconsin Valley Improvement Company (WVIC) presented a table of their calculations on the Corps estimates of potential capacity as compared to their own. He expressed concern that the Corps estimates were high due to the fact that they were estimated based on flows available only a very small percentage of the time. He also stated that, in general, hydropower plants become economically feasible at about a 20% point on the flow duration curve and that many of the Corps estimates were below the 10% points on the curves. A second comment was that the variability of head at reservoirs was not taken into consideration and that using a single value is not accurate.

- A representative of the Wisconsin Electric Power Company stated that he was in agreement with WVIC's comments on the overestimation of potential that the Corps was presenting. He stated that Wisconsin Electric Power Company uses a 20% point on the duration of potential. He expressed also concern that the data for some sites have changed from that presented in the preliminary inventories.

After the formal statements were given, the floor was opened for questions. The majority of the comments concerned the overestimation of potential capacity. An alternative computation procedure was discussed by the Corps representatives which is based on minimization of the cost of energy costs instead of the maximization of net benefits. The minimization of energy costs produces generally more reasonable estimates of potential, but may be erratic for some sites.

Other comments included a question on how the power produced at Federal dams would be valued, the question of development of small sites (less than 1 MW) not examined by this report and several questions relating to the National Study such as policies concerning the future marketing of power produced at Federal sites as well as discussion on a pumped storage study to be conducted in the next several months.

The questions relating to the National Study were answered by the Corps National Study Manager, and several questions on small hydro development were answered by a representative of the Federal Energy Regulatory Commission.

Creative Input

The 14 August 1980 public meeting resulted in a number of requests for site specific information as well as the distribution of results for the alternative potential computations procedure. Many owners supplied more accurate basic data which were incorporated directly into the data base, including existing capacity and noting the presence of hydromechanical power which is now included in existing capacity.

Result

The major result of the meeting was the reevaluation of the original computational procedure for calculation of potential capacity. A reprocessing of all sites was carried out using the 20% points on the flow duration curves as the most accurate estimate of potential capacity. The results of this final procedure are presented in Chapter 8 of this report.

Chapter 7
INVENTORY

7.1 STAGE 1, 2 AND 3 RESULTS

The data collection and screening of hydropower sites took place through a gradual process by which the data were continually updated and improved. The various stages of the screening process were discussed in Chapter 5.

Stage I

The initial phase of the study began in 1978 with an examination of the National Inventory of Dams (Ref. 7-1) totalling nearly 50,000 sites across the nation, plus other potential locations which were identified by other agencies, in particular the Federal Energy Regulatory Commission (FERC). In the MAIN Reliability Council 1,520 sites were evaluated. It was obvious at the onset that, because of the flat topography in the MAIN area, few if any undeveloped sites could be economically developed for hydropower production.

In July 1979, the Corps IWR published a preliminary inventory of potential hydropower sites in six volumes (Ref. 7-2) corresponding to the six regions shown in Figure 7-1. The initial screening procedures reduced the total number of sites from approximately 50,000 nationwide to about 17,500. The 1,520 sites in MAIN were then reduced to 763. The initial results showed a wide variation of plant factors and capacities. The three sites in MAIN that show the largest incremental capacities are: Bagnell Dam on the Lake of the Ozarks (potential of 130 MW); Lock and Dam 26 on the Mississippi River (potential of 120 MW); and, Lock and Dam 19 on the Mississippi River (potential of 104 MW).

Stage II

The results of the Stage II screening showed positive incremental net benefits for about 203 sites. The majority of the sites were run-of-the-river sites with minimal storage. A high percentage of the sites (about 80%) had existing hydropower capacity. The majority of these sites are Corps of Engineers Reservoirs and Navigation Dams. The one major exception is Bagnell Dam which is owned by the Union Electric Company. This is a large storage project and impounds the Lake of the Ozarks in Missouri.

Stage III

Additional data were collected to develop the Form 2 data base. Refined hydrologic, economic, environmental and social data reduced the number of sites to 112. Based upon this refined data it was possible to

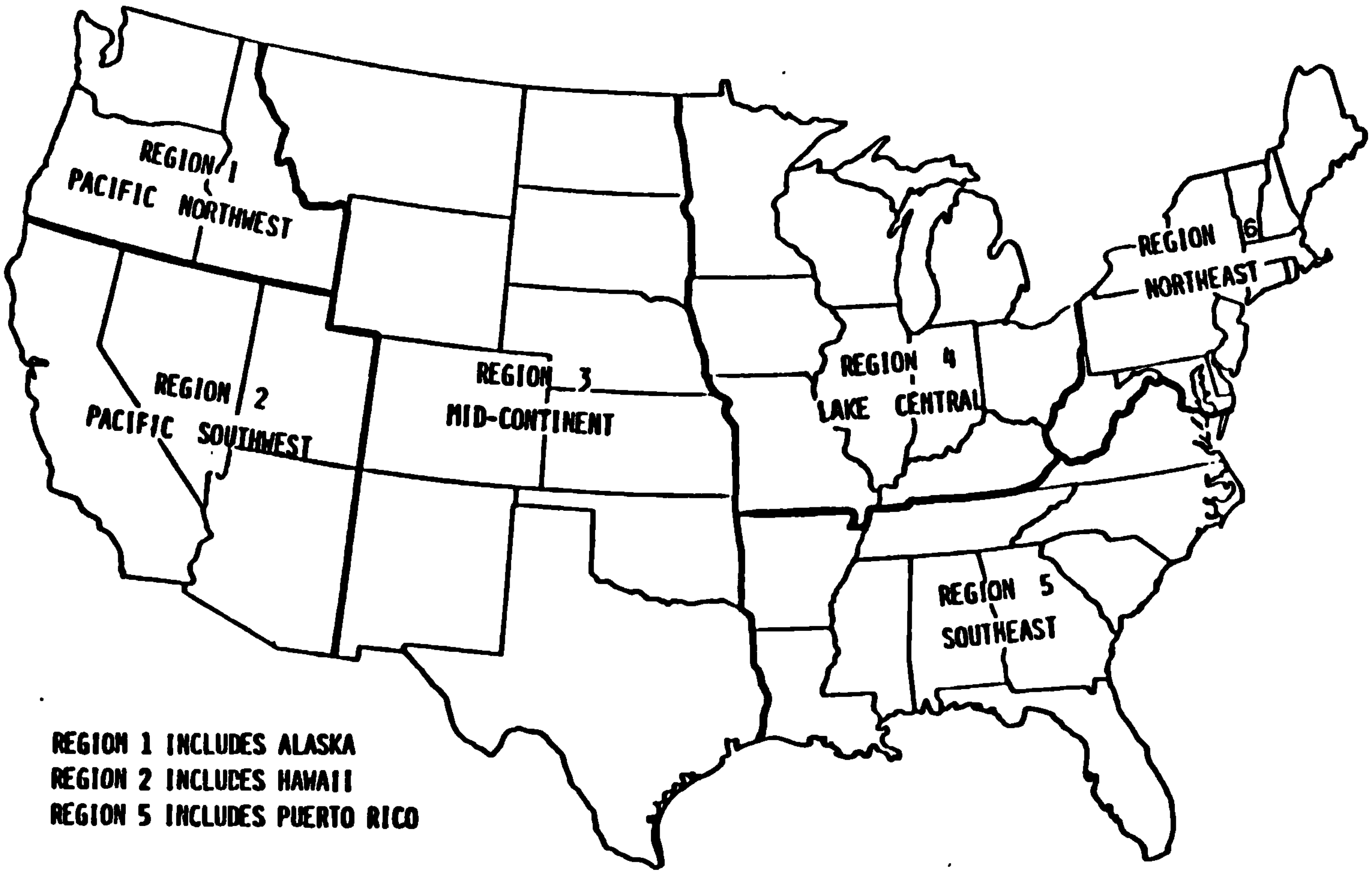


Figure 7-1

REGIONS AS DEFINED FOR THE PRELIMINARY INVENTORY OF HYDROPOWER RESOURCES identify those elements which were most likely to cause significant environmental and social impacts. 85 of the sites were found to be suitable for installation of additional or initial hydropower capacity. The remaining 27 sites were left in the data base due to their existing capacity.

As a result of the Stage III screening it was possible to eliminate all of those sites within the undeveloped sites category. Environmental, social, and economic constraints preclude the feasible development of new sites for hydroelectric power at this time. All of those sites which are carried forward to the inventory either already have a hydroelectric facility or would not require the creation of a new impoundment.

The final list of remaining sites in the active file consists of three types of projects. The first type consists of projects which have demonstrated good economic potential for incremental hydropower generation. The second type consists of projects which do not have potential, but have an existing capacity of at least 1 MW. These sites were retained in order to be able to define the complete hydroelectric system in the area. The third type consists of sites where the B/C ratio is less than 1.0. These sites were retained in case the costs or benefits change significantly so that they could be reconsidered. The Stage III results showed that 27 sites had an existing capacity of 1 MW or greater, but lacked potential incremental capacity. The Stage III studies showed 85 sites which have potential for additional hydropower generation.

Table 7-1 presents the projects which remained after the Stage III screening. Of the 84 sites with existing hydropower which are listed in the table, 3 sites may be classified as large scale. Small scale is defined (in this report) as less than 25 MW and large scale is greater than 25 MW. As a result of owner supplied data, the data base was adjusted to more accurately reflect current conditions. Table 7-2 presents the results of the inventory by stages and Corps Divisions, while Table 7-3 shows the results by stages and states.

7.2 STAGE 4 INVENTORY

Stage 4 consisted primarily of ranking all sites in the MAIN area according to economic, environmental, social and institutional criteria. No sites in the MAIN area were deleted between the Stage 3 and Stage 4 screenings. Photographs of representative projects in the MAIN area are shown in Figures 7-2, 7-3 and 7-4. Figure 7-2 shows a Federal navigation project, Figure 7-3 shows a non-Federal hydropower project and Figure 7-4 shows a Federal multi-purpose project. The map of MAIN with the location of potential sites are in Appendix C.

Once the final sites were selected using the above screenings, the determination of B/C ratios and cost of energy were based upon the total potential at the 20% point on the flow duration curve, unless site specific constraints indicated that 20% was too high a level of potential. This is the case in the majority of the Lock and Dam sites where there is no water

Table 7–1

MAIN SITES

PROJECT NAME	PROJECT NUMBER	STATE	COUNTY	STREAM	HEAD (FEET)	DRAINAGE AREA (SQ. MILES)	STORAGE (ACRE-FT)	AVG. FLOW (C.F.S)	PURPOSE*
Alexander	0246	WI	Lincoln	Wisconsin	24.0	2520.0	7388	2400.0	HR
Alton Lake (L/D 26)	0018	IL	Madison	Mississippi	14.8	171500.0	6	99103.9	N
Au Train	0008	MI	Alger	Au Train	13.8	80.0	0	67.3	H
Bagnell Dam	0094	MO	Miller	Osage	117.4	1400.0	1927000	981.0	HR
Big Quinnessec	0043	WI	Dickinson	Menominee	91.9	2475.0	11822	2516.0	H
Biron	0319	WI	Wood	Wisconsin	24.0	5341.0	20064	4781.0	HCR
Brandon Rd	0202	IL	Will	Des Plaines	33.1	1506.0	0	1972.2	N
Brule Island	0070	WI	Iron	Brule	58.6	1050.0	21800	1067.4	H
Caldron Falls	0237	WI	Marinette	Peshtigo	67.9	496.0	0	428.6	HR
Carlyle Dam	0006	IL	Clinton	Kaskaskia	25.0	2680.0	0	2053.9	CR
Carp Intake	0095	MI	Marquette	Carp River	607.3	66.0	0	78.0	H
Castle Rock	0194	WI	Adams	Wisconsin	36.2	6845.0	150000	3748.7	HCR
Cedars	0261	WI	Outagamie	Fox River	11.7	6110.0	0	4090.7	HN
Centralia	0320	WI	Wood	Wisconsin	16.0	5400.0	1500	4834.0	HR
Chalk Hill	0113	WI	Menominee	Menominee	28.0	3500.0	10500	2908.8	H
Clearwater	0123	MO	Reynolds	Black	30.1	898.0	391000	960.3	C
Combined Locks	0254	WI	Outagamie	Fox River	20.9	6150.0	0	4284.0	HNR
Dayton Dam	0107	IL	LaSalle	Fox River	24.9	2570.0	0	1632.3	H
Depere	0215	WI	Brown	Fox River	6.9	6240.0	0	4392.0	OH
Dixon	0004	IL	Lawrence	Rock River	8.9	8700.0	0	5093.9	H
Dresden Island	0168	IL	Grundy	Illinois	17.8	7279.0	0	9532.6	N
Dubay	0274	WI	Portage	Wisconsin	29.7	4822.0	102200	4399.8	HR
Escanaba 4	0041	MI	Delta	Escanaba	38.9	800.0	1400	861.9	H
Escanaba 1	0038	MI	Delta	Escanaba	12.9	980.0	800	1055.8	H
Escanaba 3	0040	MI	Delta	Escanaba	19.9	870.0	900	937.3	H
Escanaba	0097	MI	Marquette	Escanaba	66.9	346.0	0	379.8	H
Fordam	0017	IL	Winnebago	Rock River	8.9	6500.0	0	3893.8	H
Four Mile	0316	WI	Wood	Four Mile	18.0	5502.0	6000	33.0	HR
Grand Rapids	0112	WI	Menominee	Menominee	15.9	3867.0	3900	2529.3	H

Table 7-1 (Continued)

PROJECT NAME	PROJECT NUMBER	STATE	COUNTY	STREAM	HEAD (FEET)	DRAINAGE AREA (SQ. MILES)	STORAGE (ACRE-FT)	AVG. FLOW (C.F.S)	PURPOSE*
Grandfather	0241	WI	Lincoln	Wisconsin	95.1	2293.0	9780	2204.0	H
Grandmother	0245	WI	Lincoln	Wisconsin	19.0	2269.0	5761	2200.0	HR
Hat Rapids	0258	WI	Oneida	Wisconsin	21.0	1143.0	5200	1055.0	HR
Hemlock Falls	0071	MI	Iron	Michigamme	33.4	665.0	1080	710.9	H
High Falls	0232	WI	Marinette	Peshtigo	69.9	554.0	0	478.7	HR
Hoist Dam	0098	MI	Marquette	Dead River	70.0	137.0	55256	173.4	H
Johnson Falls	0236	WI	Marinette	Peshtigo	33.0	647.0	0	559.2	HR
Kaskaskia	0025	IL	Randolph	Kaskaskia	19.0	5839.0	25246	4125.0	H
Kilbourn	0215	WI	Columbia	Wisconsin	24.0	7877.0	0	6643.4	HR
Kings	0242	WI	Lincoln	Wisconsin	23.0	1297.0	18400	1198.0	HR
Kingsford	0047	WI	Dickinson	Menominee	30.1	2367.0	6185	2406.2	H
Lower Appleton	0250	WI	Outagamie	Fox River	6.9	6100.0	0	4292.0	NH
Lake Shelbyville	0029	IL	Shelby	Kaskaskia	54.0	1030.0	0	8298.0	CR
Lake Springfield	0084	IL	Sangamon	South Fork	25.0	867.0	0	668.6	
Lake Winnebago	0224	WI	Winnebago	Fox River	6.6	6040.0	2190000	4043.8	HR
Little Chute	0260	WI	Outagamie	Fox River	14.7	6120.0	0	4097.0	HRN
Little Kaukauna	0251	WI	Brown	Fox River	6.5	6100.0	0	4291.0	N
Little Quinnessec	0233	WI	Marinette	Menominee	54.9	2502.0	0	2543.4	HR
Lockport	0203	IL	Will	Chgo San.&Ship	37.9	3500.0	0	4583.9	NS
Lower Kaukauna	0256	WI	Outagamie	Fox River	20.9	6138.0	0	4319.0	HNR
Lower Menominee	0116	MI	Menominee	Menominee	11.9	3790.0	300	3497.0	H
Marquette	0099	MI	Marquette	Dead River	131.8	156.0	0	197.4	H
Marseilles	0105	IL	LaSalle	Illinois	13.0	8250.0	0	10770.4	N
McClure	0100	MI	Marquette	Dead River	49.1	140.0	3000	177.2	H
Merrill	0240	WI	Lincoln	Wisconsin	14.0	2780.0	1984	2672.0	HR
Michigamme	0072	MI	Iron	Michigamme	60.3	724.0	17212	774.0	H
Middle Appleton	0259	WI	Outagamie	Fox River	14.4	6100.0	0	4084.0	HR
Mississippi L/D 11	0026	IA	Dubuque	Mississippi	7.9	81600.0	0	40570.0	N
Mississippi L/D 12	0035	IA	Jackson	Mississippi	4.7	82400.0	0	45703.0	N
Mississippi L/D 13	0022	IA	Clinton	Mississippi	6.5	85600.0	0	47477.9	N

Table 7–1 (Continued)

PROJECT NAME	PROJECT NUMBER	STATE	COUNTY	STREAM	HEAD (FEET)	DRAINAGE AREA (SQ. MILES)	STORAGE (ACRE-FT)	AVG. FLOW (C.F.S.)	PURPOSE
Mississippi L/D 14	0059	IA	Scott	Mississippi	8.8	88400.0	0	49329.8	N
Mississippi L/D 15	0060	IA	Scott	Mississippi	10.6	88500.0	0	49324.1	N
Mississippi L/D 16	0051	IA	Muscatine	Mississippi	4.7	99400.0	0	55132.1	N
Mississippi L/D 17	0048	IA	Louisa	Mississippi	3.0	99600.0	0	52788.3	N
Mississippi L/D 18	0024	IA	Des Moines	Mississippi	6.4	113600.0	0	60208.4	N
Mississippi L/D 19	0045	IA	Lee	Mississippi	35.0	119000.0	0	63070.4	HN
Mississippi L/D 20	0077	MO	Lewis	Mississippi	5.2	134000.0	0	71020.4	N
Mississippi L/D 21	0078	MO	Marion	Mississippi	5.1	135000.0	0	71550.4	N
Mississippi L/D 22	0079	MO	Ralls	Mississippi	6.2	137500.0	0	72875.4	N
Moline Generator	0009	IL	Rock Island	Sylvan	8.9	88500.0	0	26944.6	H
Mosinee	0249	WI	Marathon	Wisconsin	2228	4126.0	6880	3440.0	HR
Nekoosa	0322	WI	Wood	Wisconsin	22.0	5500.0	3520	4924.0	HR
Peavy Falls	0073	MI	Iron	Michigamme	93.0	715.0	107800	764.4	H
Peshtigo	0234	WI	Marinette	Peshtigo	10.9	1086.0	0	937.0	HR
Petenwell	0235	WI	Juneau	Wisconsin	39.1	5860.0	432000	4929.3	HCR
Pine	0217	WI	Florence	Pine River	79.9	520.0	0	424.0	HR
Pool 24 (L/D 24)	0059	MO	Pike	Mississippi	8.0	140900.0	29700	81421.2	N
Pool 25 (L/D 25)	0051	MO	Lincoln	Mississippi	10.0	142000.0	49700	82056.8	N
Port Edwards	0342	WI	Wood	Wisconsin	17.0	5510.0	620	5055.4	HR
Potato Rapids	0235	WI	Marinette	Peshtigo	12.9	1601.0	0	1330.6	HR
Pre. Du Sac	0983	WI	Salk	Wisconsin	19.6	9000.0	119950	7570.6	HR
Prickett Dam	0021	MI	Baraga	Sturgeon	41.0	340.0	6500	410.2	H
Rainbow Reservoir	0262	WI	Oneida	Wisconsin	27.0	740.0	50161	688.0	OR
Rapide Croche	0262	WI	Outagamie	Fox River	10.2	6150.0	0	4180.5	HN
Rhinelander	0259	WI	Oneida	Wisconsin	30.9	861.0	28606	795.0	HR
Rockton	0016	IL	Winnebago	Rock River	14.9	3425.0	0	2068.5	H
Rothschild	0250	WI	Marathon	Wisconsin	21.0	4016.0	303122	2874.0	HR
Sandstone	0238	WI	Marinette	Peshtigo	33.9	675.0	0	582.4	HR
Saxon Falls	0057	MI	Gogebic	Montreal	30.9	272.0	960	340.4	H
Sears Dam	0006	IL	Rock Island	Rock River	10.9	10700.0	0	6509.9	N
Shawano	0268	WI	Shawano	Wolf River	7.2	1127.0	0	1103.3	
Sinissippi	0014	IL	Whiteside	Rock River	9.9	8715.0	0	5102.6	R
Starved Rock	0106	IL	LaSalle	Illinois R.	13.8	11056.0	0	14479.0	N
Stevens Point	0273	WI	Portage	Wisconsin	18.0	4964.0	26928	4600.0	HR
Stiles	0248	WI	Oconto	Oconto	17.9	796.0	0	686.8	HR

Table 7–1 (Concluded)

PROJECT NAME	PROJECT NUMBER	STATE	COUNTY	STREAM	HEAD (FEET)	DRAINAGE AREA (SQ. MILES)	STORAGE (ACRE-FT)	AVG. FLOW (C.F.S.)	PURPOSE
Sturgeon	0048	MI	Dickinson	Sturgeon	53.9	280.0	5700	216.8	H
Sturgeon Falls	0049	MI	Dickinson	Menominee	14.9	2940.0	3200	2988.7	H
Superior Falls	0058	MI	Cogebic	Montreal	134.8	280.0	870	350.5	H
Tomahawk	0244	WI	Lincoln	Wisconsin	16.0	2028.0	16398	1949.0	HR
Twin Falls	0045	MI	Dickinson	Menominee	43.0	1790.0	24640	1651.6	H
Upper Appleton	0253	WI	Outagamie	Fox River	9.0	6065.0	0	4267.0	NH
Upper Kaukauna	0258	WI	Outagamie	Fox River	19.1	6138.0	0	4109.5	HRN
Upper Menominee	0115	MI	Menominee	Menominee	10.9	4061.0	750	3375.1	H
Upper Oconto	0249	WI	Oconto	Oconto	24.9	750.0	0	647.1	HR
Upper Shawano	0270	WI	Shawano	Wolf River	12.9	850.0	0	832.1	
Victoria Diversion	0129	WI	Ontonagon	Ontonagon	77.4	650.0	3500	525.8	H
Wappapello	0018	MO	Wayne	St. Francis	49.0	131.0	1134600	1531.9	C
Wausau	0251	WI	Marathon	Wisconsin	26.8	3092.0	3283	2900.0	HR
Way	0074	MI	Iron	Michigamme	34.5	645.0	119950	689.5	H
White Rapids	0114	WI	Menominee	Menominee	27.3	3228.0	5925	2682.8	H
Whiting-Plover	0341	WI	Portage	Wisconsin	8.0	5150.0	160	4725.1	HR
Wisconsin R. Div	0344	WI	Portage	Wisconsin	22.0	4980.0	880	4569.1	HR
Wisconsin Rapids	0321	WI	Wood	Wisconsin	31.0	5391.0	5590	4826.0	HR

*PURPOSE: H = Hydropower; R = Recreation; N - Navigation; S = Water Supply; C = Flood Control; O = Other

Table 7-2

MAIN STUDY AREA BY DIVISIONS

Stage 1, 2, and 3 Screening

Division	Total Inventory	Stage 1 Results	Stage 2 Results	Stage 3 Results
NCD	1181	559	174	103
LMVD	244	160	27	7
MRD	73	31	1	1
SWD	22	12	1	1
MAIN TOTAL	1520	763	203	112

Table 7-3

MAIN STUDY AREA BY STATES

Stage 1, 2, and 3 Screening

State	Total Inventory	Stage 1 Results	Stage 2 Results	Stage 3 Results
Illinois	783	375	52	27
Missouri	332	174	21	8
Michigan	146	68	47	28
Wisconsin	259	146	83	49
MAIN TOTAL	1520	763	203	112

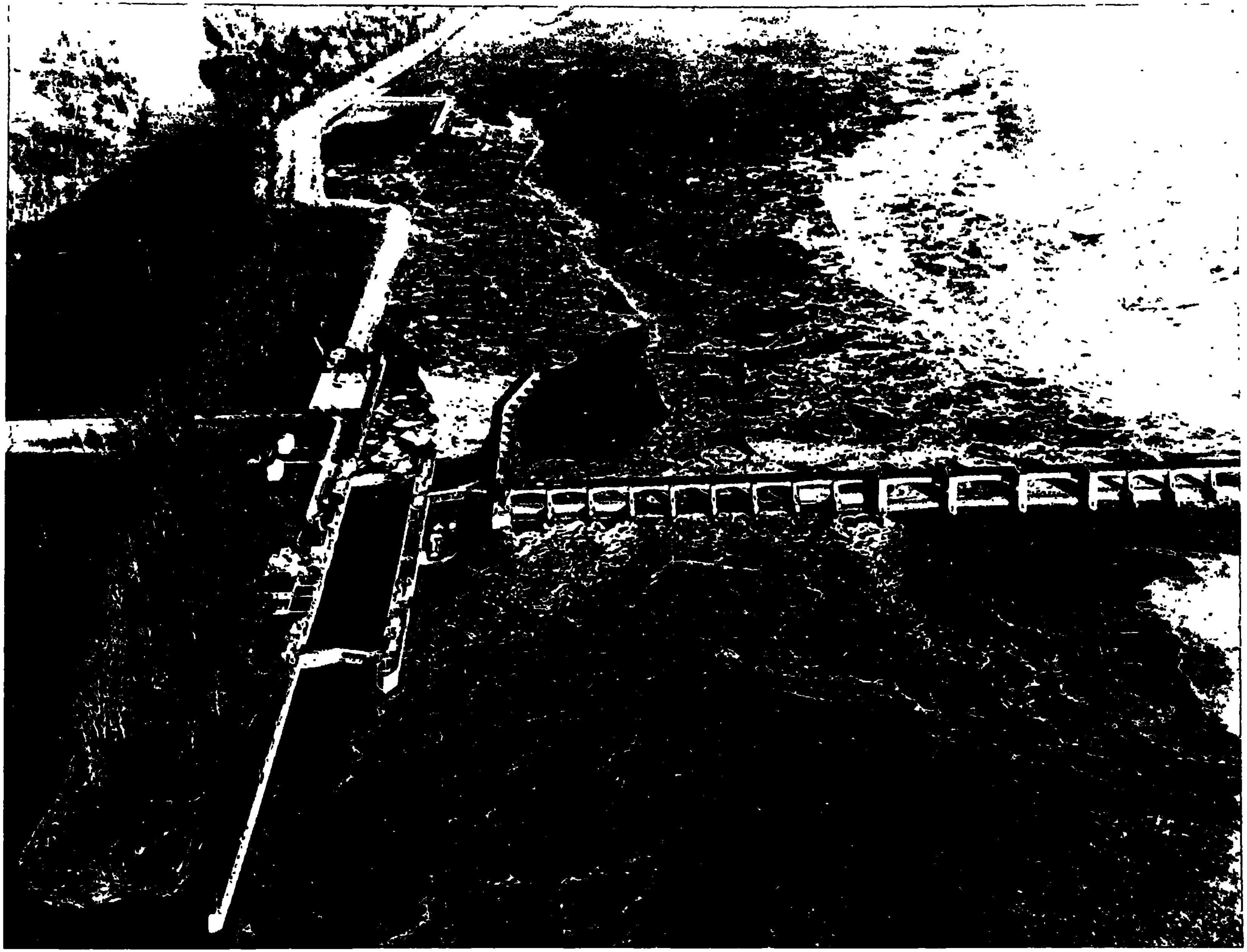


Figure 7-2

LOCK AND DAM 25, WINDFIELD, MISSOURI

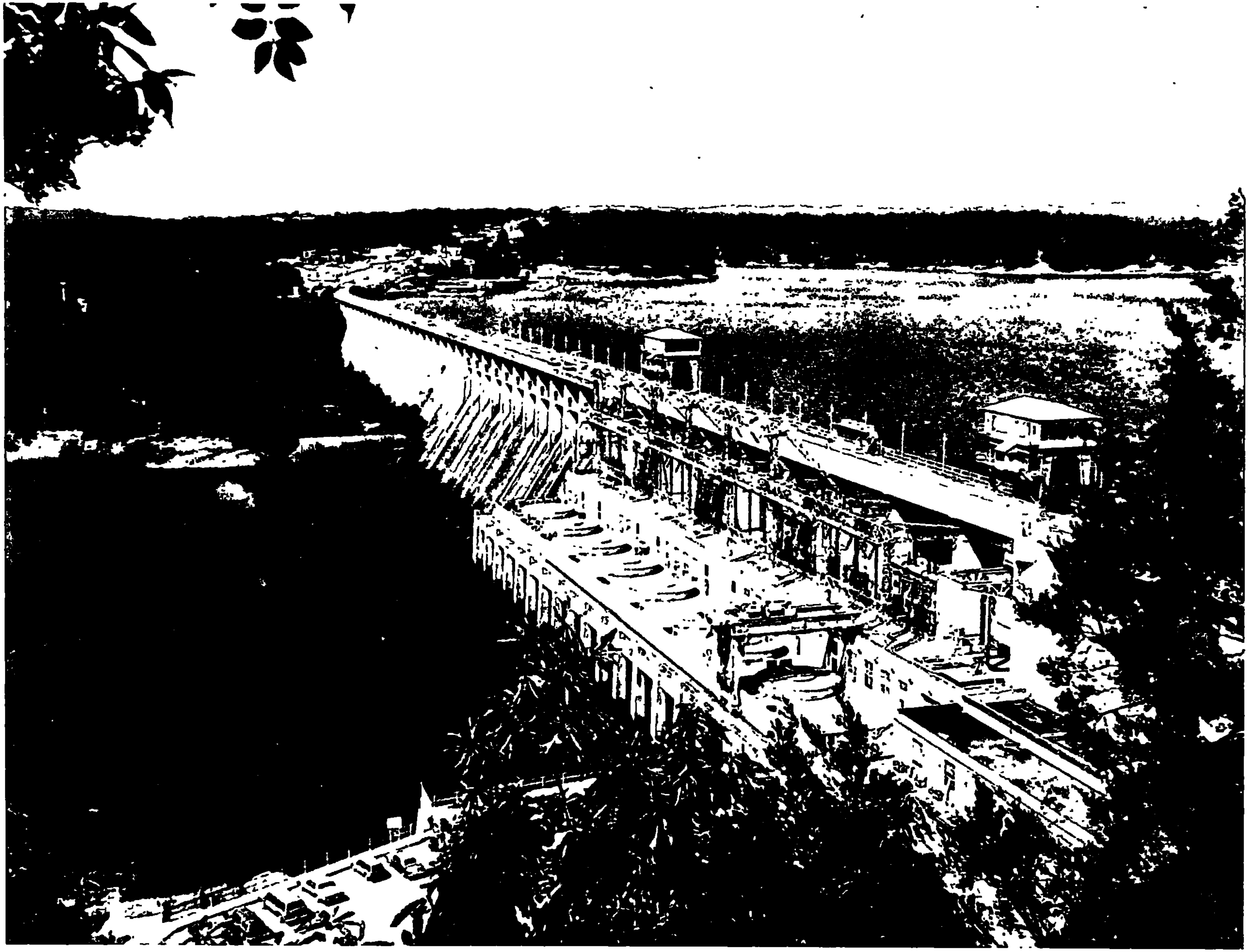


Figure 7-3
BAGNELL DAM, OSAGE BEACH, MISSOURI

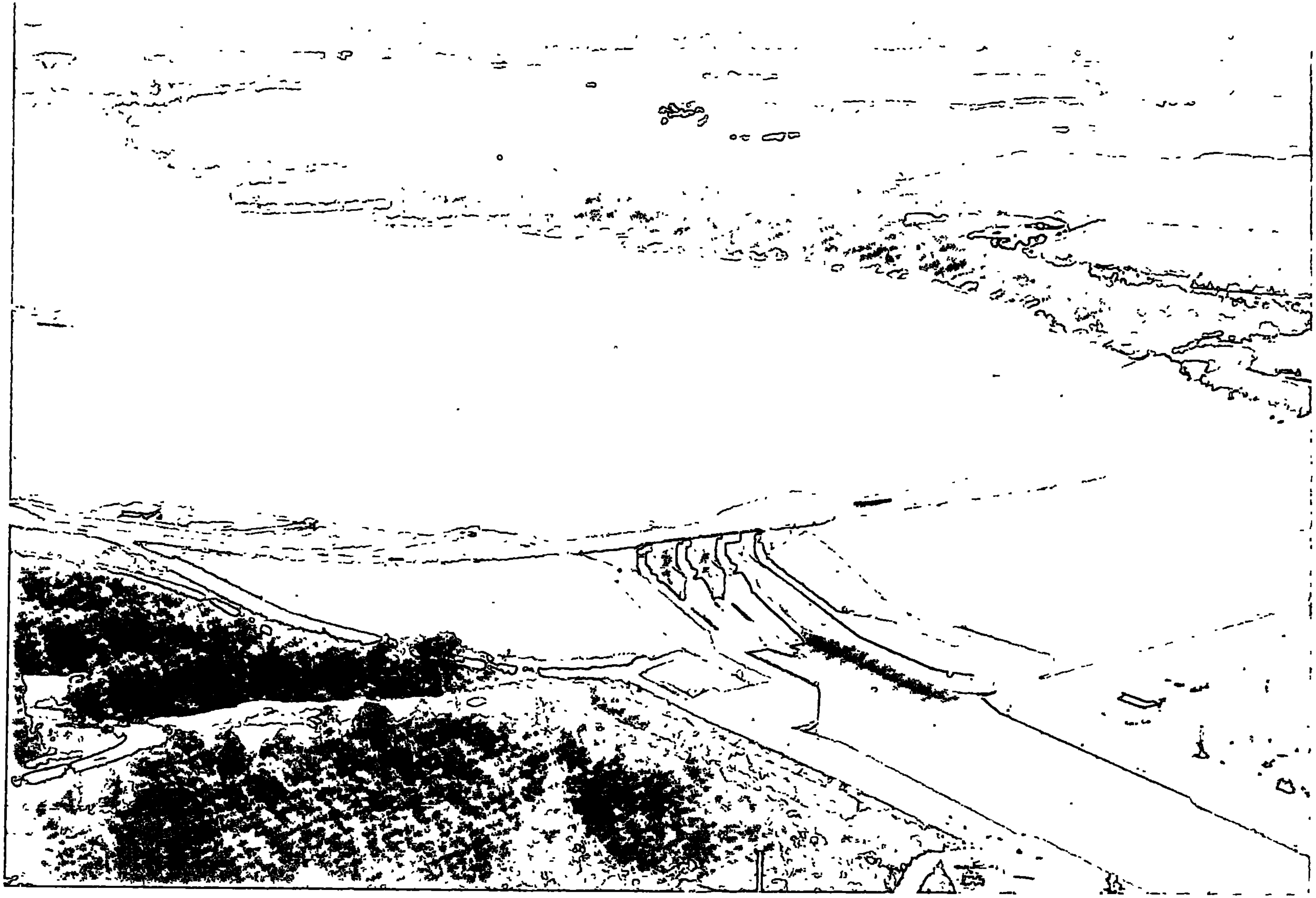


Figure 7-4

LAKE SHELBYVILLE, SHELBYVILLE, ILLINOIS

available at 20% because of the navigation aspects of the projects. Additionally, a number of existing sites without additional potential are installed beyond the 20% point (see Table 8-1).

Environmental and Social Conditions

The extent to which environmental and social impacts may incrementally constrain the development of hydropower potential at the remaining sites is unknown. Incremental losses of hydropower may occur as a result of environmental constraints upon the operation of a specific facility. For example, the Lincoln County-Grandmother facility in Wisconsin and the Carp Intake Dam in Michigan utilize penstocks which can seriously reduce summertime low flows in a segment of the natural stream. Hydropower generation at these or similar facilities may be incrementally constrained by an amount equal to that derived from the flow needed to maintain the natural low flow of the stream. In those cases where such an incremental loss has a negative effect on the over-all economic feasibility, total hydropower potential would be lost. The hydropower potential as reported in this study may be overestimated by an amount equal to unknown site specific environmental constraints.

REFERENCES

7-1. Department of Energy, "Inventory of Power Plants in the United States," Washington D.C., December

7-2. Institute for Water Resources, National Hydroelectric Power Resources Study, Preliminary Inventory of Hydropower Resources, July 1979.

Chapter 8
EVALUATION

8.1 REGIONAL PLAN DEVELOPMENT PROGRAM

Development of a regional plan consisted of an analysis and ranking of sites which passed through the previous screening stages. No undeveloped sites were identified. The environmental effects of adding hydropower at the existing sites is expected to be minimal. Thus, the environmental assessment did not remove any site from the inventory. The results of the National Hydropower Study for MAIN are presented in Table 8-1.

Recommended System

Sites having a benefit cost ratio (BCR) of 0.6 or greater were retained in the inventory for future detailed analysis which could result in benefit/cost ratios of 1.0 or greater. It was also considered that such sites may have an attractive incremental cost of energy. This is based on the fact that nine federal navigation projects have BCR between 0.8 and 1.0, but have attractive (less than 30 Mills/KWHR) costs of incremental cost of energy.

Rationale For Optimization

Improved estimates of capacity and energy in Chapter 5 were obtained from a site specific flow duration analysis. The initial hydropower potential was computed with the objective of maximizing net benefits. This objective is consistent with the Principles and Standards of the Water Resources Council.

An examination of the maximized net benefits indicated that several of the sites would be over installed. The fourth column of Table 8-1 shows the point on the flow duration curve which corresponds to the preliminary capacity selected. As seen, several proposed sites have hydropower capacity estimates computed for flows which would occur less than 20 percent of the time.

The owners of several sites in MAIN have indicated in writing and at the August 1980 public meeting that it is not economically feasible to install hydropower equipment which requires flows which would occur less than 20 percent of the time. Therefore, the final results for MAIN capacities and energies were computed based on the 20 percent criterion and they appear reasonable and proper.

Economic and Environmental Screenings

Hydropower projects for 112 sites in the regional system passed both economic and environmental screenings. Eighteen sites have B/C ratios of

Table 8-1

RESULTS OF HYDROPOWER POTENTIAL IN THE MAIN AREA

	Preliminary Results				Final Results			
Project Name	Existing Capacity (KW)	Existing Energy (MWHR)	Total Capacity (KW)	Corresponding % on Flow Duration Curve	Total Capacity* (KW)	Total Energy* (MWHR)	Cost of Energy* (Mills/KWHR)	B/C Ratio
Alexander	4200	28550	12603	3	5237	30889	1.80	2.97
Au Train	1200	4510	1200	10	1200	5125	32.17	.98
Bagnell Dam	172000	440000	302000	5	302000	580000	16.99	2.88
Big Quinessec	16000	110715	20454	22	21006	122063	3.01	1.56
Biron	6601	45780	14364	13	10009	54315	3.79	3.94
Brandon Road	0	0	17848	1	6297	36068	13.51	2.02
Brule Island	6000	33750	19093	1	6000	15100	23.67	1.89
Caldron Falls	6400	18110	6400	2	6400	17000	37.08	1.17
Carlyle	0	0	12064	5	5245	17079	28.14	1.23
Carp Intake	0	0	6927	4	4905	27577	14.53	1.97
Castle Rock	15000	97570	19521	19	18906	106365	1.68	3.49
Cedars	2700	20140	3594	35	4530	25798	5.60	1.86
Centralia	3250	25590	4864	34	6746	36610	8.76	1.67
Chalk Hill	6633	40290	12074	9	7622	42277	2.94	1.08
Clearwater	0	0	5540	7	2514	11376	2.57	1.12
Combined Locks	1995	17230	11717	9	8115	46388	10.51	1.76
Dayton	3760	18080	9206	5	4389	19317	1.42	3.69
Depere	1122	9265	1718	52	2744	15692	12.52	1.13
Dixon	3200	19740	4843	19	4735	23397	5.50	1.63
Dresden Island	0	0	11639	35	15142	89916	17.21	1.63
Dubay	8400	54360	18690	10	11182	60684	2.11	3.35
Escanaba #1	1950	7130	1950	12	1950	6700	56.65	.62
Escanaba #3	2500	9530	4674	5	2500	9900	36.00	.92
Escanaba #4	4740	17410	9229	4	4700	14000	30.00	1.52
Escanaba	2000	10090	2447	19	2326	10606	3.34	3.09
Fordham	0	0	1540	57	3151	16870	34.82	.83
Four Mile	2920	24335	5464	35	7733	41964	10.43	1.52
Grand Rapids	7020	26140	7020	5	7020	36500	28.74	1.00
Grand Father	17240	108065	17696	24	18861	111256	1.60	1.30

*Based on the 20 percent point on the duration curve

Table 8-1 (Continued)

Project Name	Preliminary Results: Existing Capacity (KW)	Existing Energy (MWHR)	Total Capacity (KW)	Corresponding % on Flow Duration Curve	Final Results: Total Capacity* (KW)	Total Energy* (MWHR)	Cost of Energy* (Mills/KWHR)	B/C Ratio
Grand Mother	3000	20365	5490	10	3772	22018	1.88	3.10
Hat Rapids	800	6830	3917	3	2094	12421	9.72	1.31
Hemlock Falls	2600	13690	6301	1	2600	13800	20.68	1.36
High Falls	7000	20695	7000	4	7000	15000	43.47	.97
Hoist Dam	4400	7155	4400	4	4400	14800	33.43	1.02
Johnson Falls	3520	11540	3520	5	3520	12000	26.54	1.46
✓ Kaskaskia	0	0	10853	10	8305	27419	33.38	1.04
Kilbourn	9600	68490	20879	10	14396	80967	4.03	2.21
Kings	2459	15165	4340	4	2602	15437	.74	28.88
Kingsford	7200	39480	22132	1	7200	31200	18.34	1.86
Lower Appleton	1443	11195	1668	53	2683	15402	9.68	1.91
✓ Lake Shelbyville	0	0	12167	5	4514	14691	21.77	1.58
Lake Springfield	0	0	2848	10	2820	7600	46.87	.90
Lake Winnebago	250	2190	870	84	871	7526	35.31	.89
Little Chute	3300	25000	10985	4	5691	32664	6.08	1.48
Little Kaukauna	100	875	1592	51	2491	14314	26.62	1.00
Little Quinnessec	8388	62345	25579	4	12695	73767	1.85	5.36
Lockport	13500	73390	24925	1	13500	62800	13.47	2.43
Lower Kaukauna	4800	36070	11723	9	8099	46447	6.64	1.22
Lower Menominee	2240	17620	4912	12	3752	21937	6.68	1.24
Marquette	3200	11225	3200	14	3200	12000	28.09	1.18
Marseilles	2024	15510	9257	35	12617	74792	16.37	1.62
McClure	9863	5595	9863	1	9863	42933	13.51	2.12
Merrill	840	7350	5067	10	3375	19889	13.58	1.40
Michigamme	9400	28900	9400	3	9400	42000	25.79	1.16
Middle Appleton	1262	10735	9948	1	5672	31514	12.98	1.46
✓Lock + Dam 11	0	0	10649	92	10649	72647	19.64	1.46
✓Lock + Dam 12	0	0	14181	60	14181	71112	26.42	.89
✓Lock + Dam 13	0	0	15580	79	15580	88288	22.91	.96
✓Lock + Dam 14	0	0	20347	67	20347	145006	17.86	1.46

*Based on the 20 percent point on the duration curve

Table 8–1 (Continued)

Project Name	Existing Capacity (KW)	Preliminary Results: Existing Energy (MWHR)	Preliminary Results: Total Capacity (KW)	Corresponding % on Flow Duration Curve	Final Results: Total Capacity* (KW)	Final Results: Total Energy* (MWHR)	Final Results: Cost of Energy* (Mills/KWHR)	B/C Ratio
Lock + Dam 15	0	0	23290	92	23291	120122	24.62	.94
Lock + Dam 16	0	0	18290	53	18290	91762	26.29	.90
Lock + Dam 17	0	0	10948	70	10949	45260	32.49	.85
Lock + Dam 18	0	0	18185	75	18186	106567	22.49	.96
Lock + Dam 19	128000	805000	231831	19	231831	117731	11.94	2.49
Lock + Dam 20	0	0	21859	71	21859	104996	26.76	1.00
Lock + Dam 21	0	0	19365	81	19366	92041	27.09	.99
Lock + Dam 22	0	0	20413	81	20414	114669	22.67	1.07
Lock + Dam 24	0	0	19991	95	47808	225955	32.80	.82
Lock + Dam 25	0	0	21528	95	78249	342333	37.80	.75
Lock + Dam 26	0	0	119433	40	119433	522274	17.41	1.63
Moline Generating	3600	31535	17624	70	19678	154822	12.53	1.56
Mosinee	3050	26270	12568	9	8172	48205	7.80	1.82
Nekoosa	4150	33525	16295	9	9448	51271	7.63	2.36
Peavy Falls	16000	44545	16000	2	16000	63860	18.60	1.74
Peshtigo	584	4340	649	39	989	5417	12.05	.84
Petenwell	20000	102280	20000	15	20000	102000	10.47	2.63
Pine	4000	17950	6745	6	4000	19000	21.55	1.24
Port Edwards	3100	25255	5070	36	7314	39684	10.19	1.47
Potato Rapids	1380	8740	3114	5	1616	8912	3.10	1.79
Prarie Du Sac	28500	4190	52033	1	28500	126944	25.15	1.22
Prickett Diversion	2200	8740	4078	4	2200	9400	24.73	1.29
Rainbow Reservoir	0	0	3804	1	1705	11070	21.99	1.25
Rapid Croche	2400	17800	3047	37	3980	22479	6.40	1.40
Rhinelander	2700	14355	5120	1	2700	10000	29.19	1.24
Rockton	1100	9095	1474	51	2772	14823	13.58	1.10
Rothschild	4210	30670	9534	10	5937	35038	3.81	2.22
Sandstone	3840	12100	3840	4	3840	15000	22.06	1.53
Saxon Falls	1250	10200	23886	1	3294	18012	9.72	1.29

*Based on the 20 percent point on the duration curve

Table 8-1 (Concluded)

Project Name	Existing Capacity (KW)	Existing Energy (MWKR)	Total Capacity (KW)	Corresponding % on Flow Duration Curve	Total Capacity* (KW)	Total Energy* (MWHR)	Cost of Energy* (Mills/KWHR)	B/C Ratio
	Preliminary Results				Final Results			
Sears Dam	0	0	4588	39	7423	36647	30.53	.89
Shawano	256	1660	336	96	659	3962	22.38	.73
Sinissippi	0	0	4836	24	5270	26030	30.14	.98
✓ Starved Rock	0	0	16481	20	17608	99015	21.56	1.62
Stevens Point	4800	32575	11660	10	6977	37861	6.13	1.30
Stiles	1500	6960	2242	5	1500	7000	37.94	.73
Sturgeon	800	4470	4969	1	1148	5207	4.41	1.79
Sturgeon Falls	3500	22555	4764	15	4067	23637	1.64	1.60
Superior Falls	1800	13940	12399	5	3521	18992	7.55	1.19
Tomahawk	2600	16165	4214	10	2809	16573	1.27	2.00
Twin Falls	6233	37120	22765	1	6365	37361	.16	9.31
Upper Appleton	1990	15085	4737	10	3430	19705	7.69	1.41
Upper Kaukauna	5600	37865	14558	4	7405	42334	5.14	1.04
Upper Menominee	916	7980	4451	14	3468	19128	15.59	1.18
Upper Oconto	1320	8045	3032	4	1552	8503	2.27	2.72
Upper Shawano	700	5165	741	37	984	5869	6.84	1.03
Victoria Diversion	12000	23510	12000	4	12000	64000	16.54	1.59
✓ Wappapello	0	0	22200	5	9232	32687	15.90	2.01
Wausau	5400	38090	11785	8	7188	42398	3.56	1.92
Way	2000	12595	6308	1	2313	13273	1.59	2.66
White Rapids	7883	39670	10612	9	7883	40040	17.15	1.75
Whiting-Plover	854	7380	1832	50	3217	17455	16.12	1.47
Wisc. River Diversion	6567	41960	14751	9	8554	46416	3.44	4.32
Wisconsin Rapids	10051	64105	21302	10	13050	70813	2.23	7.19
TOTAL	704,854	3,341,275	1,807,539		1,610,588	7,207,876		

*Based on the 20 percent point on the duration curve

0.6 or greater, but less than 1.0. There are 26 sites with existing hydropower, but no additional potential. These sites have been carried through the final screenings to insure that their existing capacities are included in the Regional Plan. This leaves 86 sites with developable potential.

Annual costs and benefits were determined utilizing computer routines that incorporate the following: a flow duration curve based on daily flow data; regional benefit curves developed by the Federal Energy Regulatory Commission (relating energy and capacity benefits to annual plant factor); and, generalized cost curves (relating power head to total powerhouse costs for a range of installed capacities). In some cases, sequential routing techniques using reservoir simulation in a monthly sequential analysis were utilized to determine capacity and energy for selected storage projects. The Hydropower Cost Estimating Manual, May 1979, a publication from the Institute for Water Resources, provides the basic cost estimating criteria for this analysis. Selection of generator units was based on net head and unit cost curves and charts for Kaplan, Francis, and small-scale units. Using curve-fitting techniques based on ten individual installed capacities for each project, the installed capacity that maximizes net benefits was selected at the point where the greatest positive departure of benefits to costs occurred. The economic analysis used a discount rate of 6-7/8 percent, an economic life of 100 years, and the cost levels of July 1978.

Impacts

Since all of the potential hydropower sites in the regional system are existing reservoirs, any impacts associated with the projects would result from an increase in fluctuating water surfaces both in the reservoir and downstream. For the larger storage projects, an analysis to determine the optimum operating pool elevations will be necessary to determine the associated impacts. The impacts associated with run-of-river projects would be minimal since the projects store little, if any, water and alterations to the normal regime of the stream would be minimal.

Constraints

The constraints associated with the regional system can be divided into three major categories - physical, social, and institutional.

The major physical constraint would be the configuration of the existing dam at the potential sites. Our analysis assumed that hydropower would be added without major alterations to the existing features. Thus, the existing head and storage capabilities associated with each dam limit the additional capacities. A second major physical constraint would be the compatability of the added power function with the existing project purpose such as irrigation, navigation, water supply, hydropower, flood control, and diversion projects. The analysis of the sites included in the regional system assumed that the water would be available for hydropower release.

The social constraints include identification and preservation of historical, cultural, and archaeological sites, and the preservation of scenic and recreational areas along the streams below the projects. There were no major social constraints identified for the existing projects since most operate within specified parameters, maintaining allowable maximum and minimum releases.

The major institutional constraint would be the existing state water laws for each project.

8.2 SCHEDULE FOR DEVELOPMENT

Since it is unlikely that all of the 112 sites would be developed at the same time, a logical order of priority for this development would be required. The existing hydropower and any additional hydropower which could be developed as a result of this study would provide only a small portion of the overall MAIN existing and projected capacity and energy. Since there is a need for a large amount of capacity to meet summer peak loads, the order of preference has been given to capacity rather than energy; thus a larger plant would have higher priority over a smaller plant.

Since the monetary value of hydropower depends on its selling price, it was decided that the ranking of the sites for schedule prioritization would be based on the incremental cost of energy (Mills/ KWHR). This ranking has the added feature of providing an easy measure of a site's attractiveness while comparing it to other types of electric generation. This comparison is especially important for private hydropower developments. Since 71 percent of the sites in the MAIN regional plan are privately owned, this feature is especially desirable.

In order to categorize the potential site developments, projects were classified into two time frames, near-term and long-term. Near-term projects are those in which hydropower could be added at existing dams in the 10-year period between 1980 and 1990. This 10-year period would give enough time to complete a study and construct the hydropower facilities at the existing dam.

The cut-off value for separating near-term and long-term sites was determined to be a value of 30 Mills/KWHR. This value was obtained from the Chicago Regional Office of the Federal Energy Regulatory Commission. It appears to be a logical delineation for more desirable versus less desirable hydropower sites in the MAIN area for the near future. The economic attractiveness of the long-term hydropower sites may increase in the future, if the oil prices continue to escalate.

Current Plans for Hydropower Development

Currently, some hydropower development studies in the MAIN area are being pursued by the Corps of Engineers. The Rock Island District is studying hydropower at Brandon Road, Dresden Island, Marseilles, and Starved Rock on the Illinois River and Lock and Dam 11, Lock and Dam 14 and Lock and Dam 22 on the Mississippi River.

The St. Louis District is currently studying hydropower at Lock and Dam 26 on the Mississippi River and at Lake Shelbyville and Carlyle Lake on the Kaskaskia River.

The Eastern Iowa Light and Power Cooperative has applied to the FERC for studies to develop hydropower at four navigation projects on the Mississippi River Lock and Dam 13, Lock and Dam 16, Lock and Dam 17, and Lock and Dam 18.

A permit has been granted for a private applicant to study hydropower production at the Sears Dam on the Rock River.

The City of Carlyle, Illinois, has received a FERC permit to study hydropower at Carlyle Lake.

Pumped Storage Hydropower in MAIN

There are two pumped storage hydropower sites in MAIN. These two projects have been removed from the MAIN inventory because of the latest change in boundary, which places these sites in the Southwest Power Pool (SWPP). One project is the Taum Sauk Project, located in Reynolds County, Missouri, an offstream pumped storage type owned by the Union Electric Company. The other pumped storage project in MAIN, the Clarence Cannon Project in Ralls County, Missouri, is in the final stages of construction by the St. Louis District, Corps of Engineers, and has both conventional and reversible turbines. The project is located on the Salt River and is expected to go on line in 1983.

Conclusion

In conclusion, the study shows that for the Mid America Interpool Network there are 112 sites with a total existing capacity of 704,854 KW and a total potential capacity of 1,610,588 KW. Of these sites, 27 are in the State of Illinois, 49 in the State of Wisconsin, 28 in the State of Michigan and 8 in the State of Missouri. Of these sites 30 are Federal and 82 are private. There are 16 sites suitable for long-term development (cost of energy greater than 30 Mills/KWHR) and 96 sites suitable for development in the near-term category (cost of energy less than 30 Mills/KWHR). Eighteen of the 112 sites have a B/C ratio less than 1.0. Although the study has shown that hydropower would not generate a high percentage of the MAIN area's power, complete development would result in a doubling of the existing capacity. This use of a renewable resource would be a desirable step towards achieving energy independence for our country.

APPENDICES

APPENDIX A
EXISTING GENERATING CAPABILITY

This appendix shows all existing capability that was available at the beginning of 1978.

All generating units are listed by system. Joint ownership units may be shown in either of two ways. Identify the method used, either A or B, for each joint ownership unit. Only one method is to be used in a regional report and all owners of a jointly owned plant must use the same method.

Method A: Each owner reports his share as net dependable capability in Columns 05 and 06 and cross references the other shares in a footnote but does not total other shares in his capability.

Method B: The system operating the plant reports the full capability in Columns 05 and 06 and lists all shares in a footnote. Shares are also accounted for where appropriate as scheduled imports and exports in Item 2-C.

To facilitate reporting, the following abbreviations are to be used: Column 01: Identify each system by a 4 character letter code. For convenience, the name of the system is to be displayed opposite the 4 character letter code on the next page of this filing.

Column 03: To give the location of each generating station, use the Federal Information Processing Service (FIPS) state (two digits) and county (three digit) codes. (ANS X 3.31-1973)

Column 04: Identify the type of unit:

ST	Steam Turbine-non nuclear
NB	Steam-BWR Nuclear
NP	Steam-PWR Nuclear
NH	Steam-HTGR Nuclear
IC	Internal Combustion
GT	Combustion Turbine
HY	Conventional Hydro
PS	Pumped Storage Hydro
CW	Combined Cycle-Steam Portion-Waste Heat Only
CA	Combined Cycle-Steam Portion-Auxiliary Fired

CT	Combined Cycle-Combustion Turbine Portion
JE	Jet Engine
FC	Fuel Cell
SO	Solar
WM	Wind Power
GE	Geothermal
ZZ	None of the above (Described in Footnote)

*MAIN, "Regional Reliability Council, Coordinated Bulk Power Supply Program", April 1, 1979.

Columns 07&09: Identify type of fuel:

WH	Waste Heat
COL	Coal (general)
BIT	Bituminous Coal
SUB	Sub-Bituminous Coal
ANT	Anthracite Coal
LIG	Lignite Coal
PC	Petroleum Coke
LNG	Liquified Natural Gas
MTH	Methanol
GAS	Gas (general)
NG	Natural Gas
RG	Refinery Gas
BFG	Blast Furnace Gas
COG	Coke Oven Gas
GST	Geothermal Steam
MUL	Multi-Fueled
REF	Refuse (solid waste)
OIL	Oil (general)
FO1	No. 1 Fuel Oil
FO2	No. 2 Fuel Oil
FO4	No. 4 Fuel Oil
FO5	No. 5 Fuel Oil
FO6	No. 6 Fuel Oil
CRU	Crude Oil
TOP	Top Crude Oil
JF	Jet Fuel
KER	Kerosene
LPG	Liquid Propane Gas
RRO	Re-Refined Motor Oil
SNG	Synthetic Natural Gas
UR	Uranium
PL	Plutonium
WAT	Water
SUN	Sun
WND	Wind

Fuel brought to the plant site that is converted before combustion process, such as for a coal gasification system is to be identified as type ZZ and explained in a footnote.

Columns 08&10: Identify principle methods of transporting fuel to the plant site:

WA	Water Transportation
TK	Truck
RR	Railroad
PL	Pipeline
CV	Conveyer

Column 11: State the number of days that the unit would operate on the alter fuel only, at normal loads, before shutdown would be necessary because of operating problems such as boiler fouling, etc. Leave blank if use of alternative fuel is limited only by storage or availability.

EXISTING GENERATING CAPABILITY — REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

				PRIMARY FUEL				ALTERNATE FUEL			
			UNIT	NET CAPABILITY MW		FUEL	TRANSP.	FUEL	TRANSP.	DAYS	
SYSTEM	STATION NAME AND UNIT NO.	LOC.	TYPE	SUMMER	WINTER	TYPE	METHOD	TYPE	METHOD	USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
	ILLINOIS-MISSOURI POOL										
	CENTRAL ILLINOIS PUBLIC SERVICE CO.										
CEIP	COFFEEN 1	17-135	ST	260.0	260.0	COL	CV TK				
CEIP	COFFEEN 2	17-135	ST	480.0	480.0	COL	CV TK				
CEIP	GRAND TOWER 3	17-077	ST	72.0	74.0	COL	RR TK				
CEIP	GRAND TOWER 4	17-077	ST	103.0	104.0	COL	RR TK				
CEIP	HUTSONVILLE 1	17-033	ST	27.5	29.0	F02	TK				
CEIP	HUTSONVILLE 2	17-033	ST	27.5	29.0	F02	TK				
CEIP	HUTSONVILLE 3	17-033	ST	75.0	78.0	COL	RR TK				
CEIP	HUTSONVILLE 4	17-033	ST	75.0	78.0	COL	RR TK				
CEIP	HUTSONVILLE DIESEL	17-033	IC	3.0	3.0	F02	TK				
CEIP	MEREDOSIA 1	17-137	ST	63.5	64.5	COL	WA TK				
CEIP	MEREDOSIA 2	17-137	ST	63.5	64.5	COL	WA TK				
CEIP	MEREDOSIA 3	17-137	ST	180.0	180.0	COL	WA TK				
CEIP	MEREDOSIA 4	17-137	ST	188.0	200.0	F06	WA TK	KER	WA TK		
CEIP	JOPPA (6 UNITS)	17-127	ST	203.0	203.0	COL	WA RR				*1
CEIP	NEWTON 1	17-079	ST	566.0	565.0	COL	RR				
	ILLINOIS POWER CO.										
ILPC	BALDWIN 1-3	17-157	ST	1800.0	1815.0	COL	RR				
ILPC	JOPPA (6 UNITS)	17-127	ST	203.0	203.0	COL	RR				*1

EXISTING GENERATING CAPABILITY

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
ILPC	HAVANA 1-5	17-125	ST	260.0	264.0	F06	WA				
ILPC	HAVANA 6	17-125	ST	426.0	434.0	COL	WA				
ILPC	HENNEPIN 1&2	17-155	ST	308.0	320.0	COL	WA	NG	PL		
ILPC	VERMILION 1&2	17-183	ST	182.0	184.0	COL	TK				
ILPC	VERMILION CT	17-183	GT	12.0	14.0	F02	TK				
ILPC	WOOD RIVER 1-3	17-119	ST	150.0	152.0	F02	TK	NG	PL		
ILPC	WOOD RIVER 4	17-119	ST	103.0	104.0	COL	RR	NG	PL		
ILPC	WOOD RIVER 5	17-119	ST	397.0	405.0	COL	RR				
ILPC	OGLESY 1-4	17-099	GT	60.0	71.0	F02	TK	NG	PL		
ILPC	STALLINGS 1-4	17-199	GT	91.0	107.0	F02	TK	NG	PL		
ILPC	JACKSONVILLE GT	17-137	GT	13.0	14.0	F02	TK				
ILPC	JACKSONVILLE DIESELS	17-137	IC	4.0	4.0	F02	TK				
ILPC	VANDALIA	17-051	IC	2.0	2.0	F02	TK				
ILPC	BLOOMINGTON	17-113	IC	4.6	4.6	F02	TK				
ILPC	MARSEILLES	17-099	HY	2.4	2.4	WAT					
	UNION ELECTRIC COMPANY										
UNEC	ASHLEY (4 UNITS)	29-510	ST	69.0	50.0	F06	PL				
UNEC	HOWARD BEND COMB. TURBINE	29-189	GT	43.0	49.0	F02	TK				
UNEC	JOPPA (6 UNITS)	17-127	ST	405.0	405.0	BIT	RR				*1
UNEC	KEOKUK (15 UNITS)	19-111	HY	119.0	122.0	WAT					
UNEC	LABADIE (4 UNITS)	29-071	ST	2220.0	2228.0	BIT	RR				
UNEC	MERAMEC (4 UNITS)	29-189	ST	722.0	722.0	BIT	RR	NG	PL		*4
UNEC	MERAMEC COMB. TURBINE	29-189	GT	53.0	63.0	F02	TK				
UNEC	OSAGE (8 UNITS)	29-131	HY	212.0	203.0	WAT					
UNEC	RUSH ISLAND (2 UNITS)	29-099	ST	1150.0	1154.0	BIT	RR				
UNEC	SIOUX (2 UNITS)	29-183	ST	904.0	918.0	BIT	RR				
UNEC	TAUM SAUK	29-179	PS	300.0	225.0	WAT					
UNEC	VENICE (8 UNITS)	17-119	ST	441.0	453.0	F02	TK	NG	PL		
UNEC	VENICE COMB. TURBINE	17-119	GT	23.0	30.0	F02	TK				
UNEC	CANTON DIESELS (6 UNITS)	29-111	IC	5.0	5.0	F02	TK				*2
UNEC	FAIRGROUNDS COMB. TURBINE	29-051	GT	54.0	64.0	F02	TK				*2
UNEC	KIRKSVILLE COMB. TURBINE	29-001	GT	12.0	15.0	NG	PL				*2
UNEC	LAGRANGE DIESEL	29-111	IC	1.0	1.0	F02	TK				*2

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
UNEC	MEXICO	29-007	ST	21.0	22.0	NG	PL				*2
UNEC	MOBERLY DIESELS (2 UNITS)	29-175	IC	2.0	2.0	F02	TK				*2
UNEC	MONTGOMERY DIESEL	29-139	IC	1.0	1.0	F02	TK				*2
UNEC	PORTABLE DIESEL	29-	IC	1.0	1.0	F02	TK				*2
UNEC	CHARLESTON DSL. (2 UNITS)	29-133	IC	2.0	2.0	F02	TK				*3
UNEC	VIADUCT COMB. TURBINE	29-031	GT	25.0	32.0	NG	PL				*3
UNEC	MEXICO COMB. TURBINE	29-007	GT	55.0	65.0	F02	TK				
UNEC	MOBERLY COMB. TURBINE	29-175	GT	55.0	65.0	F02	TK				
UNEC	MOREAU COMB. TURBINE	29-051	GT	55.0	65.0	F02	TK				

*1.) JOPPA PLANT IS JOINTLY OWNED BY ILLINOIS POWER CO.(203MW), CENTRAL ILLINOIS PUBLIC SERVICE(203MW), KENTUCKY UTILITIES (203MW) AND UNION ELECTRIC(405MW).

*2.) GENERATION OWNED AND OPERATED BY MISSOURI POWER & LIGHT, WHICH IS A WHOLLY OWNED SUBSIDIARY OF UNION ELECTRIC.

*3.) GENERATION OWNED AND OPERATED BY MISSOURI UTILITIES WHICH IS A WHOLLY OWNED SUBSIDIARY OF UNION ELECTRIC.

*4.) CAPABILITY OF MERAMEC UNITS REDUCED TO MEET EPA RESTRICTIONS.

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL NET CAPABILITY MW SUMMER	PRIMARY FUEL NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL TRANSP. METHOD	ALTERNATE FUEL FUEL TYPE	ALTERNATE FUEL TRANSP. METHOD	ALTERNATE FUEL DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
	WISCONSIN-UPPER MICHIGAN SYSTEMS										
	MADISON GAS AND ELECTRIC CO.										
MAGE	BLOUNT STREET 1-5	55-025	ST	54.0	56.0	COL	RR	NG	PL		05
				36.5	37.4	F02	TK	NG	PL		05
MAGE	BLOUNT STREET 6&7	55-025	ST	99.7	100.0	COL	RR	NG	PL		
MAGE	COLUMBIA 1	55-021	ST	115.0	115.6	SUB	RR				01
MAGE	COLUMBIA 2	55-021	ST	112.0	115.4	COL	RR				02
MAGE	FITCHBURG 1&2	55-025	GT	41.0	53.0	F02	TK	NG	PL		
MAGE	KEWAUNEE 1	55-061	NP	93.4	92.1	UR	TK				04
MAGE	NINE SPRINGS 1	55-025	GT	14.0	20.0	F02	TK	NG	PL		
MAGE	SYCAMORE 1&2	55-025	GT	34.0	45.0	F02	TK	NG	PL		
	WISCONSIN ELECTRIC POWER COMPANY										
WIEP	POINT BEACH 1	55-071	NP	495.0	495.0	UR	TK				
WIEP	POINT BEACH 2	55-071	NP	495.0	495.0	UR	TK				
WIEP	POINT BEACH 5	55-071	GT	16.0	24.0	F02	TK				
WIEP	PORT WASHINGTON 1	55-089	ST	63.0	64.0	BIT	WA				
WIEP	PORT WASHINGTON 2	55-089	ST	76.0	77.0	BIT	WA				
WIEP	PORT WASHINGTON 3	55-089	ST	76.0	77.0	BIT	WA				
WIEP	PORT WASHINGTON 4	55-089	ST	78.0	79.0	BIT	WA				
WIEP	PORT WASHINGTON 5	55-089	ST	77.0	79.0	BIT	WA				
WIEP	PORT WASHINGTON 6	55-089	GT	18.0	23.0	F02	TK				
WIEP	VALLEY 1	55-079	ST	130.0	127.0	BIT	WA				
WIEP	VALLEY 2	55-079	ST	137.0	127.0	BIT	WA				
WIEP	VALLEY 3	55-079	IC	3.0	3.0	F02	TK				
WIEP	WELLS 1	55-079	ST	10.0	12.0	BIT	TK				
WIEP	COMMERCE	55-079	ST	31.0	27.0	F02	TK	NG	PL		
WIEP	HYDRO (16 PLANTS)		HY	74.0	76.0	WAT					
WIEP	LAKESIDE	55-079	ST	261.0	261.0	F02	TK	F06	TK		
								NG	PL		
WIEP	LAKESIDE	55-079	GT	34.0	40.0	F02	TK	NG	PL		

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	WINTER	FUEL TYPE	TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	TRANSP. METHOD	DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
WIEP	OAK CREEK 1	55-079	ST	108.0	110.0	COL	WA RR				
WIEP	OAK CREEK 2	55-079	ST	94.0	96.0	COL	WA RR				
WIEP	OAK CREEK 3	55-079	ST	114.0	119.0	COL	WA RR				
WIEP	OAK CREEK 4	55-079	ST	114.0	119.0	COL	WA RR				
WIEP	OAK CREEK 5	55-079	ST	246.0	251.0	COL	WA RR				
WIEP	OAK CREEK 6	55-079	ST	246.0	251.0	COL	WA RR				
WIEP	OAK CREEK 7	55-079	ST	281.0	282.0	COL REF	WA RR TK				
WIEP	OAK CREEK 8	55-079	ST	284.0	286.0	COL REF	WA RR TK				
WIEP	OAK CREEK 9	55-079	GT	20.0	25.0	F02	TK	NG	PL		
WIEP	GERMANTOWN 1	55-131	GT	52.0	66.0	F02	TK				
WIEP	GERMANTOWN 2	55-131	GT	52.0	66.0	F02	TK				
WIEP	GERMANTOWN 3	55-131	GT	52.0	66.0	F02	TK				
WIEP	GERMANTOWN 4	55-131	GT	52.0	66.0	F02	TK				
	WISCONSIN POWER AND LIGHT CO.										
WIPL	BLACKHAWK 3&4	55-105	ST	49.7	43.4	COL	RR				
WIPL	COLUMBIA 1	55-021	ST	243.1	242.6	SUB	RR				*1
WIPL	COLUMBIA 2	55-021	ST	236.9	242.2	COL	RR				*2
WIPL	EDGEWATER 2&3	55-117	ST.	105.8	105.2	COL	RR				
WIPL	EDGEWATER 4	55-117	ST	221.8	221.5	BIT	RR				*3
WIPL	HYDRO (VARIOUS LOCATIONS)		HY	23.0	23.0	WAT					
WIPL	KEWAUNEE	55-061	NP	215.1	212.1	UR	TK				*4
WIPL	NELSON DEWEY	55-043	ST	209.1	213.6	COL	WA				
WIPL	PRAIRIE DU SAC	55-111	HY	29.9	29.9	WAT					

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
WIPL	ROCK RIVER 1&2	55-105	ST	156.6	155.4	COL	RR				
WIPL	ROCK RIVER 3,4,5&6	55-105	GT JE	133.6	170.5	F02	TK				
WIPL	SHEEPSKIN	55-105	JE	35.5	44.1	F02	TK				
WISCONSIN PUBLIC SERVICE CORP.											
WIPS	COLUMBIA 1	55-021	ST	167.3	167.0	SUB	RR				01
WIPS	COLUMBIA 2	55-021	ST	163.0	166.7	COL	RR				02
WIPS	EAGLE RIVER	55-125	IC	4.0	4.1	F02	TK				
WIPS	EDGEWATER 4	55-117	ST	103.4	103.3	BIT	RR				03
WIPS	KEWAUNEE 1	55-061	NP	216.2	213.1	UR	TK				04
WIPS	PULLIAM 3-8	55-009	ST	378.8	384.7	BIT	WA				
WIPS	PULLIAM 1-2	55-009	ST	7.7	7.6	F02	TK	NG	PL		
WIPS	VARIOUS HYDRO		HY	66.3	67.2	WAT					
WIPS	WEST MARINETTE 31-32	55-075	JE	82.3	94.1	F02	TK	NG	PL		
WIPS	WESTON 1	55-073	ST	63.7	64.4	BIT	RR				
WIPS	WESTON 2	55-073	ST	84.6	85.9	BIT	RR	NG	PL		
WIPS	WESTON 31	55-073	GT	20.7	25.0	F02	TK	NG	PL		
WIPS	WESTON 32	55-073	JE	50.8	63.3	F02	TK	NG	PL		
UPPER PENINSULA POWER COMPANY											
UPPP	CCI	26-103	HY	15.5	15.5	WAT					
UPPP	DODGEVILLE	26-061	IC	9.1	9.1	F02	TK				
UPPP	ESCANABA 1	26-041	ST	14.4	14.4	BIT	WA				
UPPP	ESCANABA 2	26-041	ST	14.5	14.5	BIT	WA				
UPPP	ISHPEMING	26-103	IC	10.0	10.0	F02	TK				
UPPP	PORTAGE	26-061	JE	51.4	55.0	F02	TK				
UPPP	PRICKETT	26-013	HY	2.2	2.2	WAT	WA				
UPPP	VICTORIA	26-131	HY	12.3	12.3	WAT	WA				
UPPP	WARDEN	26-103	ST	17.7	17.7	BIT	TK				
UPPP	PRESQUE ISLE 1	26-103	ST	25.0	25.0	BIT	WA				
UPPP	PRESQUE ISLE 2	26-103	ST	37.4	37.4	BIT	WA				

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
UPPP	PRESQUE ISLE 3	26-103	ST	56.9	56.9	BIT	WA				
UPPP	PRESQUE ISLE 4	26-103	ST	59.6	59.6	BIT	WA				
UPPP	PRESQUE ISLE 5	26-103	ST	84.7	84.7	BIT	WA				
UPPP	PRESQUE ISLE 6	26-103	ST	83.3	83.3	BIT	WA				
UPPP	PRESQUE ISLE 7	26-103	ST	80.0	80.0	BIT	WA				
UPPP	PRESQUE ISLE 8	26-103	ST	80.0	80.0	BIT	WA				
UPPP	PRESQUE ISLE 9	26-103	ST	80.0	80.0	BIT	WA				

*1.) COLUMBIA 1 IS JOINTLY OWNED BY WPL (242.6 MW), WPS (167.0 MW) AND MG&E (115.6 MW) BASED ON WINTER RATING. BASED ON SUMMER RATING, THE SPLIT IS WPL (243.1 MW), WPS (167.3 MW) AND MG&E (115.8 MW).

*2.) COLUMBIA 2 IS JOINTLY OWNED BY WPL (242.2 MW), WPS (166.7 MW) AND MG&E (115.4 MW) BASED ON WINTER RATING. BASED ON SUMMER RATING, THE SPLIT IS WPL (236.9 MW), WPS (163.0 MW) AND MG&E (112.8 MW).

*3.) EDGEWATER 4 IS JOINTLY OWNED BY WPL (221.5 MW) AND WPS (103.3 MW) BASED ON WINTER RATING. BASED ON SUMMER RATING THE SPLIT IS WPL (221.8 MW) AND WPS (103.4 MW).

*4.) KEWAUNEE 1 IS JOINTLY OWNED BY WPS (213.1 MW), WPL (212.1 MW) AND MG&E (92.1 MW) BASED ON WINTER RATING. BASED ON SUMMER RATING, THE SPLIT IS WPS (216.2 MW), WPL (215.1 MW) AND MG&E (93.4 MW).

*5.) BLOUNT ST. 1-5 SERVED OFF COMMON HEADER SYSTEM COMPOSED OF COAL AND OIL FIRED BOILERS. CAPACITY IS SPLIT BETWEEN COAL AND OIL ON BASIS OF BOILER CAPACITY OF EACH TYPE.

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL NET CAPABILITY MW SUMMER	PRIMARY FUEL NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL TRANSP. METHOD	ALTERNATE FUEL FUEL TYPE	ALTERNATE FUEL TRANSP. METHOD	ALTERNATE FUEL DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
ASSOCIATED ELECTRIC COOP											
ASEC	CHAMOIS 1	29-151	ST	18.0	18.0	BIT	RR				
ASEC	CHAMOIS 2	29-151	ST	50.0	50.0	BIT	RR				
ASEC	GREEN FOREST	29-023	IC	10.0	10.0	NG	PL	F04	TK		
ASEC	NEW MADRID 1	29-143	ST	600.0	600.0	BIT	RR WA				
ASEC.	NEW MADRID 2	29-143	ST	600.0	600.0	BIT	RR WA				
ASEC	SOUTHRIVER 1	29-127	IC	6.0	6.0	F04	TK	NG	PL		
ASEC	SOUTHRIVER 2	29-127	ST	16.0	16.0	BIT	RR	NG	PL		
ASEC	THOMAS HILL 1	29-175	ST	180.0	180.0	BIT	RR				
ASEC	THOMAS HILL 2	29-175	ST	303.0	303.0	BIT	RR				
ASEC	UNIONVILLE 1	29-171	GT	22.0	22.0	F02	TK				
ASEC	UNIONVILLE 2	29-171	GT	22.0	22.0	F02	TK				
CENTRAL ILLINOIS LIGHT CO.											
CEIL	R.S. WALLACE 3-6	17-179	ST	50.0	50.0	COL	RR				
CEIL	R.S. WALLACE 7	17-179	ST	95.0	95.0	COL	RR				
CEIL	E.D. EDWARDS 1	17-143	ST	128.0	95.0	COL	RR				01
CEIL	E.D. EDWARDS 2	17-143	ST	255.0	180.0	COL	RR				01
CEIL	E.D. EDWARDS 3	17-143	ST	341.0	341.0	COL	RR				
CEIL	DUCK CREEK 1	17-057	ST	379.0	379.0	COL	RR				
CEIL	STERLING 1-2	17-143	GT	32.0	32.0	NG	PL				
01.) CAPACITY GAIN DURING SUMMER BY SWITCHING TO DESIGN FUEL											
COLUMBIA, MISSOURI, WATER AND LIGHT DEPT.											
COLM	COLUMBIA W&L DEPT. 2	29-019	ST	8.5	8.5	BIT	TK				
COLM	COLUMBIA W&L DEPT. 4	29-019	ST	5.0	5.0	BIT	TK				
COLM	COLUMBIA W&L DEPT. 5	29-019	ST	16.5	16.5	BIT	TK				
COLM	COLUMBIA W&L DEPT. 6	29-019	GT	10.0	10.0	NG	PL	F02	TK		
COLM	COLUMBIA W&L DEPT. 7	29-019	ST	22.0	22.0	BIT	TK				
COLM	COLUMBIA W&L DEPT. 8	29-019	ST	36.0	36.0	NG	PL	F02	TK		

EXISTING GENERATING CAPABILITY — REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
COMMONWEALTH EDISON CO.											
CECO	KINCAID 1	17-021	ST	606.0	606.0	BIT	CV				
CECO	KINCAID 2	17-021	ST	606.0	606.0	BIT	CV				
CECO	LOMBARD 31-33	17-043	JE	111.0	139.0	JF	TK				
CECO	POWERTON 5	17-179	ST	850.0	850.0	SUB	RR				
CECO	POWERTON 6	17-179	ST	850.0	850.0	SUB	RR				
CECO	QUAD CITIES 1	17-161	NB	576.0	591.0	UR	TK				*1
CECO	QUAD CITIES 2	17-161	NB	577.0	592.0	UR	TK				*1
CECO	RIDGELAND 1	17-031	ST	157.0	163.0	F06	WA				
CECO	RIDGELAND 2	17-031	ST	152.0	158.0	F06	WA				
CECO	RIDGELAND 3	17-031	ST	137.0	143.0	F06	WA				
CECO	RIDGELAND 4	17-031	ST	136.0	142.0	F06	WA				
CECO	SABROOKE 31-34	17-201	GT	121.0	147.0	F02	TK				
CECO	STATELINE 3	18-089	ST	190.0	190.0	SUB	RR				
CECO	STATELINE 4	18-089	ST	318.0	318.0	SUB	RR				
CECO	WAUKEGAN 6	17-097	ST	88.0	88.0	SUB	RR				
CECO	WAUKEGAN 7	17-097	ST	328.0	328.0	SUB	RR				
CECO	WAUKEGAN 8	17-097	ST	358.0	358.0	SUB	RR				
CECO	WAUKEGAN 31-32	17-097	JF	119.0	156.0	JF	TK				
CECO	BLOOM 33-34	17-031	GT	122.0	145.0	F02	TK				
CECO	CALUMET 31,33,34	17-031	GT	186.0	228.0	NG	PL	F02	TK		
CECO	CALUMET 32	17-031	GT	58.0	72.0	F02	TK				
CECO	COLLINS 1	17-063	ST	554.0	554.0	F06	WA				
CECO	COLLINS 2	17-063	ST	554.0	554.0	F06	WA				
CECO	COLLINS 3	17-063	ST	530.0	530.0	F06	WA				
CECO	COLLINS 4	17-063	ST	530.0	530.0	F06	WA				
CECO	COLLINS 5	17-063	ST	530.0	530.0	F06	WA				
CECO	CRAWFORD 7	17-031	ST	219.0	222.0	SUB	WA	NG	PL		*2
CECO	CRAWFORD 8	17-031	ST	319.0	326.0	SUB	WA	NG	PL		*2
CECO	CRAWFORD 31-33	17-031	GT	161.0	201.0	NG	PL	F02	TK		
CECO	DRESDEN 1	17-063	NB	197.0	207.0	UR	TK				
CECO	DRESDEN 2	17-063	NB	772.0	794.0	UR	TK				
CECO	DRESDEN 3	17-063	NB	773.0	794.0	UR	TK				

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
CECO	FISK 31-34	17-031	JE	238.0	312.0	JF	TK				
CECO	JOLIET 6	17-197	ST	330.0	340.0	SUB	RR				
CECO	JOLIET 7	17-197	ST	533.0	537.0	SUB	RR				
CECO	JOLIET 8	17-197	ST	533.0	537.0	SUB	RR				
CECO	JOLIET 9	17-197	IC	11.0	11.0	F02	TK				
CECO	JOLIET 31-32	17-197	GT	123.0	151.0	F02	TK				
CECO	WILL COUNTY 1	17-197	ST	139.0	144.0	SUB	WA				
CECO	WILL COUNTY 2	17-197	ST	161.0	167.0	SUB	WA				
CECO	WILL COUNTY 3	17-197	ST	251.0	262.0	SUB	WA				
CECO	WILL COUNTY 4	17-197	ST	510.0	520.0	SUB	WA				
CECO	ZION 1	17-097	NP	1040.0	1040.0	UR	TK				
CECO	ZION 2	17-097	NP	1040.0	1040.0	UR	TK				

01.) QUAD CITIES PLANT IS JOINTLY OWNED BY CECO(1183MW)AND IOWA ILLINOIS GAS AND ELECTRIC(395MW). BASED ON WINTER CAPABILITY.

02.) 10% OF THE TOTAL FUEL FOR THIS UNIT IS REFUSE - DERIVED FUEL.

KAUKAUNA, WISCONSIN, ELECTRIC AND WATER DEPT.

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	SUMMER	WINTER	FUEL TYPE	TRANSP. METHOD	ALT. FUEL TYPE	ALT. TRANSP. METHOD	DAYS USE	NOTES
KAUK	DIESEL	55-087	IC	6.0	6.0	F02	TK				
KAUK	ELM STREET	55-087	GT	17.0	20.0	NG	PL	F02	TK		
KAUK	MENASHA STEAM PLANT	55-139	ST	34.0	34.0	COL	RR				
KAUK	HYDRO (VARIOUS LOCATIONS)	55-087	HY	9.0	9.0	WAT					

MANITOWOC, WISCONSIN, PUBLIC UTILITIES

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	SUMMER	WINTER	FUEL TYPE	TRANSP. METHOD	ALT. FUEL TYPE	ALT. TRANSP. METHOD	DAYS USE	NOTES
MANI	MANITOWOC 2	55-071	ST	5.0	5.0	BIT	WA				
MANI	MANITOWOC 3	55-071	ST	10.0	10.0	BIT	WA				
MANI	MANITOWOC 4	55-071	ST	10.0	10.0	BIT	WA				
MANI	MANITOWOC 5	55-071	ST	22.0	22.0	BIT	WA				
MANI	MANITOWOC 6	55-071	ST	22.0	22.0	BIT	WA				

EXISTING GENERATING CAPABILITY — REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1,1980

				PRIMARY FUEL				ALTERNATE FUEL			
			UNIT	NET CAPABILITY MW		FUEL	TRANSP.	FUEL	TRANSP.	DAYS	
SYSTEM	STATION NAME AND UNIT NO.	LOC.	TYPE	SUMMER	WINTER	TYPE	METHOD	TYPE	METHOD	USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
MARQUETTE, MICHIGAN, BOARD OF LIGHT AND POWER											
MARQ	DIESEL (1-8)	26-103	IC	15.0	15.0	F02	TK				
MARQ	HYDRO (2-3)	26-103	HY	4.0	4.0	WAT					
MARQ	SHIRAS (1-2)	26-103	ST	34.0	34.0	COL	WA				
MARQ	PLANT #4 GT #1	26-103	GT	23.0	27.0	F02	TK				
MARSHFIELD, WISCONSIN, ELECTRIC AND WATER DEPT.											
MARF	WILDWOOD 2	55-141	ST	4.0	4.0	NG	PL	F02	TK		
MARF	WILDWOOD 3	55-141	ST	6.0	6.0	NG	PL	F02	TK		
MARF	WILDWOOD 4	55-141	ST	9.0	12.0	COL	RR				
MARF	WILDWOOD 5	55-141	ST	14.0	15.0	COL	RR				
ROCHELLE (ILLINOIS) MUNICIPAL UTILITIES											
ROCH	ROCHELLE - DIESEL #1	17-141	IC	.9	.9	F02	TK				
ROCH	ROCHELLE - DIESEL #2	17-141	IC	.8	.8	F02	TK				
ROCH	ROCHELLE - DIESEL #3	17-141	IC	2.7	2.7	NG	PL	F02	TK		
ROCH	ROCHELLE - DIESEL #4	17-141	IC	1.1	1.1	F02	TK				
ROCH	ROCHELLE - DIESEL #5	17-141	IC	1.1	1.1	NG	PL	F02	TK		
ROCH	ROCHELLE - DIESEL #6	17-141	IC	2.5	2.5	NG	PL	F02	TK		
ROCH	ROCHELLE - DIESEL #7	17-141	IC	4.1	4.1	NG	PL	F02	TK		
ROCH	ROCHELLE - DIESEL #8	17-141	IC	1.0	1.0	F02	TK				
ROCH	ROCHELLE - STEAM PLANT #1	17-141	ST	11.2	11.2	COL	RR				
ROCH	ROCHELLE - PEAKER #1	17-141	IC	2.7	2.7	NG	PL	F01	TK		
ROCH	ROCHELLE - PEAKER #2	17-141	IC	2.7	2.7	NG	PL	F01	TK		
SOUTHERN ILLINOIS POWER COOP.											
SOIP	MARION 1-3	17-199	ST	110.0	110.0	COL	TK				
SOIP	MARION 4	17-199	ST	175.0	175.0	COL	TK				

EXISTING GENERATING CAPABILITY

REGION MAIN

IN COMMERCIAL SERVICE BY JANUARY 1.1980

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	PRIMARY FUEL: NET CAPABILITY MW SUMMER	PRIMARY FUEL: NET CAPABILITY MW WINTER	PRIMARY FUEL: FUEL TYPE	PRIMARY FUEL: TRANSP. METHOD	ALTERNATE FUEL: FUEL TYPE	ALTERNATE FUEL: TRANSP. METHOD	ALTERNATE FUEL: DAYS USE	NOTES
01	02	03	04	05	06	07	08	09	10	11	12
SPRINGFIELD. ILLINOIS - CITY WATER LIGHT & POWER DEPT.											
SPFI	LAKESIDE 1-2	17-167	ST	20.0	22.0	FO2	TK				01
SPFI	LAKESIDE 3	17-167	ST	15.0	15.0	FO2	TK				
SPFI	LAKESIDE 4-7	17-167	ST	110.0	114.0	COL	TK				
SPFI	DALLMAN 1-2	17-167	ST	173.0	174.0	COL	TK				
SPFI	DALLMAN 3	17-167	ST	190.0	190.0	COL	TK				
SPFI	REYNOLDS 1	17-167	GT	18.0	20.0	FO2	TK				
SPFI	FACTORY 1	17-167	GT	23.0	26.0	FO2	TK				

*1.) UNITS ARE ON DEACTIVATED SHUTDOWN STATUS.

SYSTEM	STATION NAME AND UNIT NO.	LOC.	UNIT TYPE	SUMMER	WINTER	FUEL TYPE	TRANSP. METHOD	ALT. FUEL TYPE	ALT. TRANSP. METHOD	DAYS USE	NOTES
VILLAGE OF WINNETKA. ILLINOIS WATER AND ELECTRIC											
VWWE	WINNETKA POWER PLANT	17-031	IC	5.0	5.0	FO2	TK				
VWWE	WINNETKA POWER PLANT	17-031	ST	25.5	25.5	NG	PL	COL	RR TK		
WESTERN ILLINOIS POWER COOP.. INC.											
WEIL	PEARL 1	17-149	ST	22.0	22.0	COL	WA				
WEIL	PEARL COMB. TURBINE	17-149	GT	22.0	24.0	FO2	TK				
WEIL	WINCHESTER (5 UNITS)	17-171	IC	3.0	3.0	FO2	TK	NG	PL		
WEIL	PITTSFIELD (5 UNITS)	17-149	IC	9.0	9.0	FO2	TK	NG	PL		

APPENDIX B
GLOSSARY

AVERAGE LOAD - the hypothetical constant load over a specified time period that would produce the same energy as the actual load would produce for the same period.

BENEFIT-COST RATIO (B/C) - the ratio of the present value of the benefit stream to the present value of the project cost stream computed for comparable price level assumptions.

BENEFITS (ECONOMIC) - the increase in economic value produced by the hydropower addition project, typically represented as a time stream of value produce by the generation of hydroelectric power. In small hydro projects this is often limited for analysis purposes to the stream of costs that would be representative of the least costly alternative source of equivalent power.

CAPABILITY - maximum kilowatt capability of the system with all power sources available, with no allowance for outages, and with sufficient kilowatt-hours to supply the requirements of the system.

CAPACITY - the maximum power output or load for which a turbine-generator station or system is rated.

CAPACITY VALUE - that part of the market value of electric power which is assigned to dependable capacity.

COSTS (ECONOMIC) - the value required to produce the hydroelectric power.

DEMAND - SEE LOAD

DEPENDABLE CAPACITY - the load carrying ability of a hydropower plant under adverse hydrologic conditions for the time interval and period specified of a particular system load.

ENERGY - the capacity for performing work. The electrical energy term generally used is kilowatt-hours and represents power (kilowatts) operating for some time (hours).

ENERGY VALUE - that part of the market value of electric power which is assigned to energy generated.

FEASIBILITY STUDY - an investigation performed to formulate a hydropower project and definitively assess its desirability for implementation.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) - an agency in the Department of Energy which licenses non-Federal hydropower projects and regulates interstate transfer of electric energy. Formerly the Federal Power Commission (FPC).

FIRM ENERGY - the energy generation ability of a hydropower plant under adverse hydrologic conditions for the time interval and period specified of a particular system load.

FOSSIL FUELS - refers to coal, oil, and natural gas.

HEAD, GROSS (H) - the difference in elevation between the headwater surface above and the tailwater surface below a hydroelectric power plant, under specified conditions.

HYDROELECTRIC PLANT OR HYDROPOWER PLANT - an electric power plant in which the turbine-generators are driven by falling water.

INSTALLED CAPACITY - the total of the capacities shown on the nameplates of the generating units in a hydropower plant.

KILOVOLT ((KV) - one thousand volts.

KILOWATT (KW) - one thousand watts.

KILOWATT-HOUR (KWH) - the amount of electrical energy involved with a one kilo-watt demand over a period of one hour. It is equivalent to 3,413 BTU of heat energy.

LOAD - the amount of power needed to be delivered at a given point on an electric system.

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 during a designated period to the peak or maximum load occurring in that period.

MARGIN - difference between net system capacity and system maximum load requirements.

MEGAWATT (MW) - one thousand kilowatts.

MEGAWATT-HOURS (MWH) - one thousand kilowatts-hours.

NUCLEAR ENERGY - energy produced largely in the form of head during nuclear reactions, which, with conventional generating equipment, can be transferred into electric energy.

NUCLEAR POWER - power released from the heat of nuclear reactions, which is converted to electric power by a turbine-generator unit.

PEAKING CAPACITY - that part of a system's capacity which is operated during the hours of highest power demand.

PEAK LOAD - the maximum load in a stated period of time.

PLANT FACTOR - ratio of the average load to the installed capacity of the plant expressed as an annual percentage.

POWER (ELECTRIC) - the rate of generation or use of electric energy, usually measured in kilowatts.

POWER FACTOR - the percentage ratio of the amount of power, measured in kilowatts, used by a consuming electric facility to the apparent power measured in kilovolt-amperes.

POWER-POOL - two or more electric systems which are interconnected and co-ordinated to a greater or lesser degree to supply, in the most economical manner, electric power for their combined loads.

PREFERENCE CUSTOMERS - publicly-owned systems and non-profit cooperatives who by law have preference over investor-owned systems for the purchase of power from Federal projects.

PROJECT SPONSOR - the entity controlling the small hydro site and promoting construction of the facility.

PUMPED STORAGE - an arrangement whereby electric power is generated during load periods by using water previously pumped into a storage reservoir during off-peak periods.

RECONNAISSANCE STUDY - a preliminary feasibility study designed to ascertain whether a feasibility study is warranted.

SECONDARY ENERGY - all hydroelectric energy other than FIRM ENERGY

SPINNING RESERVE - generating units operating at no load or at partial load with excess capacity readily available to support additional load.

STEAM-ELECTRIC PLANT - a plant in which the prime movers (turbines) connected to the generators are driven by steam

SURPLUS POWER - generating capacity which is not needed on the system at the time it is available.

SYSTEM, ELECTRIC - the physically connected generation, transmission, distribution, and other facilities operated as an integral unit under one control management or operating supervision.

THERMAL PLANT - a generating plant which uses heat to produce electricity. Such plants may burn coal, gas, oil or use nuclear energy to produce thermal energy.

THERMAL POLLUTION - rise in temperature of water such as that resulting from heat released by a thermal plant to the cooling water when the effects on other uses of the water are detrimental.

TRANSMISSION - the act or process of transporting electric energy in bulk.

TURBINE - the part of a generating unit which is spun by the force of water or steam to drive an electric generator. The turbine usually consists of a series of curved vanes or blades on a central spindle.

WATT - the rate of energy transfer equivelent to one ampere under a pressure on volt at unity power factor.

NHS MAPS

Two maps are inserted into the adjacent pocket. One is an index map and one is a site location map. The primary purpose of the index map is to show the National Electric Reliability Council (NERC) regions, the Corps of Engineers division and district boundaries, and Corps office locations. A separate regional report and accompanying site location map has been prepared for each of the NERC regions depicted on the index map.

The second map shows existing and potential hydroelectric site locations for the subject region and is intended to provide general information to the reader about the sites. The size of a project is depicted by the diameter of the circle and the type of project by color. Each site symbol on the map is labeled with a four digit number which corresponds to a ten character National Hydroelectric Power Resources Study site identification code. Each part of the 10 character ID code helps to narrow down the source of information for that site. For example, a typical site identification code is shown below:

```
             O R   A   N P P   9 9 9 9
               |   |    |        |
       State --    |    |         ---- Site ID Number
Type of Project ---      ---- Corps Division and District
```

Consequently, for more information about a site, one needs to determine from the map a site's state and county, the Corps division and district, and the four digit number. With the site ID number, the site can then be located in the list of sites in the regional report or in Volume XII of the NHS final report. If more detailed information is desired, the appropriate Corps division and/or district office may be contacted.

☆U.S. GOVERNMENT PRINTING OFFICE: 1982-373-819

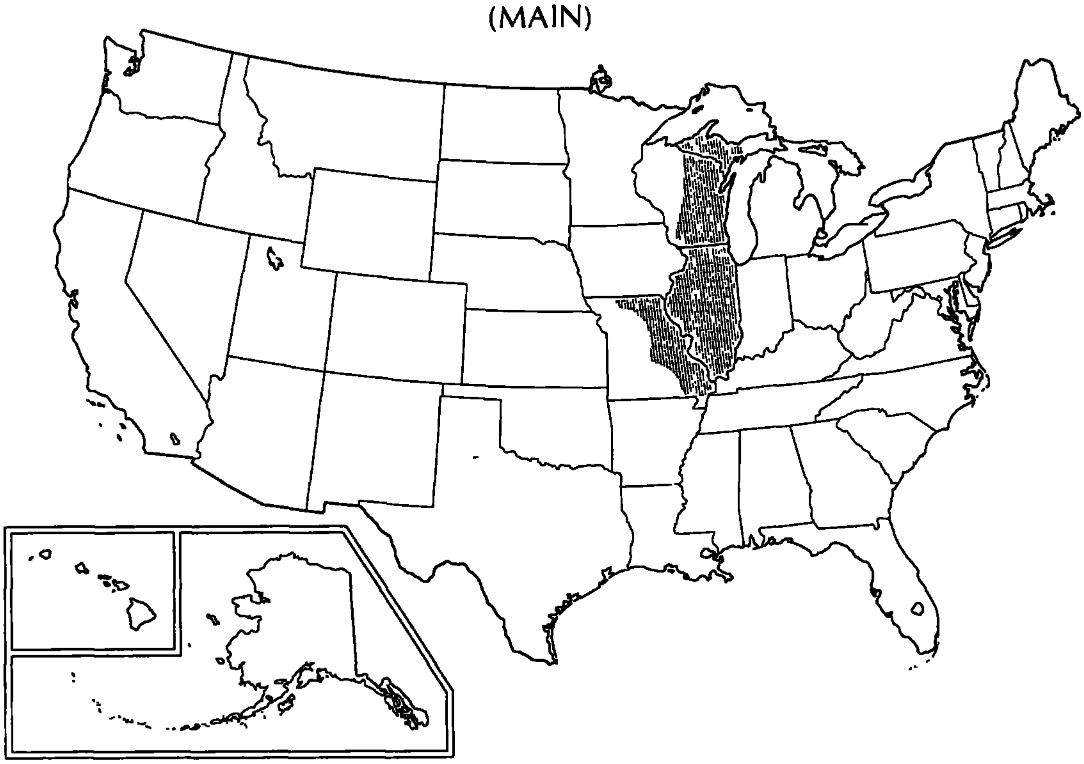
NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

INDEX TO NATIONAL ELECTRIC RELIABILITY COUNCIL REGIONS


MAIN REGION
MID AMERICAN INTERPOOL NETWORK
Subregion boundary
Electric Reliability Council regions may overlap as a result of transmission line interties
HYDROELECTRIC SITES
Existing dam: power potential fully developed
Existing dam: power potential partially developed
Existing dam: power potential undeveloped
Potential site: further study recommended
GENERATING CAPACITY
25 megawatts and greater
Less than 25 megawatts
CORPS OF ENGINEERS
Division boundary; office
District boundary; office
Division and district office
Albers Equal Area Projection
SCALE 1:2,000,000
MILES
KILOMETRES
Prepared for the U. S. Army Engineer Institute for Water Resources as a part of
the National Hydroelectric Power Resources Study by the U. S. Geological Survey, 1980
CANADA
LAKE SUPERIOR
LAKE MICHIGAN
MICH
WIS
WISCONSIN
ILLINOIS
WISCONSIN UPPER MICHIGAN SYSTEM (WUMS)
COMMONWEALTH EDISON CO. (CECO)
COMMONWEALTH EDISON CO. (CECO)
ILLINOIS-MISSOURI SUBREGION
CHICAGO
Rock Island
Peoria
Springfield
St. Louis
Jefferson City
IOWA
MISSOURI
MISSOURI
ILLINOIS
Green Bay
Madison
Milwaukee

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

MID AMERICA INTERPOOL NETWORK (MAIN)




ELECTRIC RELIABILITY COUNCIL REGIONS OF THE UNITED STATES
Prepared for the U. S. Army Engineer Institute for Water Resources as a part of the National Hydroelectric Power Resources Study by the U. S. Geological Survey, 1980.
Albers Equal Area Projection
SCALE 1:7,500,000
MILES
KILOMETERS
ELECTRIC RELIABILITY COUNCILS
NPCC Northeast Power Coordinating Council
MAAC Mid Atlantic Area Electric Reliability Coordination Agreement
ECAR East Central Area Reliability Coordination Agreement
SERC Southeastern Electric Reliability Council
MAIN Mid American Interpool Network
MARCA Mid Continent Area Reliability Coordination Agreement
SWPP Southwest Power Pool
ERCOT Electric Reliability Council of Texas
WSSC Western Systems Coordinating Council
Region boundary
Electric Reliability Council regions may overlap as a result of transmission line interties
CORPS OF ENGINEERS
Division boundary; office
District boundary; office
Division and district office
Puerto Rico is included within the SERC Region
WSCC
MARCA
MAIN
ECAR
NPCC
MAAC
ECAR
SWPP
SERC
ERCOT
NORTH PACIFIC
SOUTH PACIFIC
MISSOURI RIVER
NORTH CENTRAL
NEW ENGLAND
NORTH ATLANTIC
OHIO RIVER
SOUTHWESTERN
LOWER MISSISSIPPI VALLEY
SOUTH ATLANTIC
PACIFIC OCEAN
ATLANTIC OCEAN
LAKE SUPERIOR
LAKE HURON
LAKE ONTARIO
LAKE ERIE
PACIFIC OCEAN
FORT SHAFTER
Principal Islands of HAWAII
ALASKA
NORTH PACIFIC