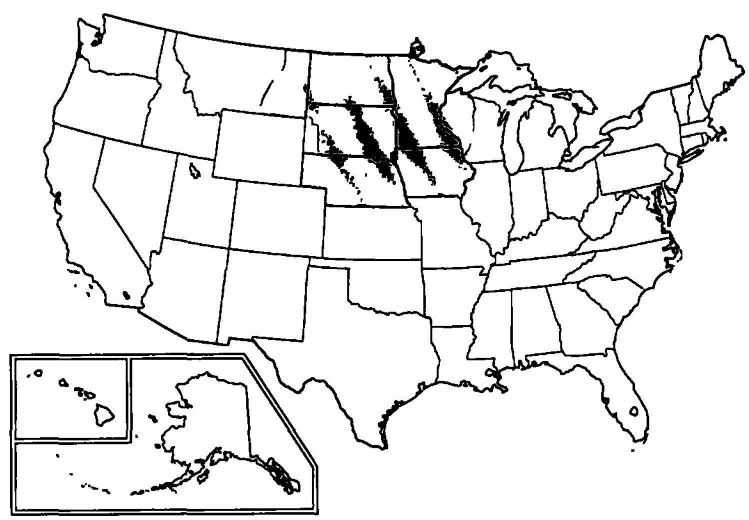
US Army Corps
of Engineers

**National
Hydroelectric Power
Resources Study**

Volume XIX
September 1981

Regional Assessment: Mid-Continent Area Reliability Coordination Agreement



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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-Continent Area Reliability Coordination Agreement. 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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US ARMY CORPS OF ENGINEERS
NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

REGIONAL REPORT: VOLUME XIX
MID-CONTINENT AREA RELIABILITY COORDINATION AGREEMENT

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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 XIX, describes the hydroelectric power potential in the Mid-Continent Area Reliability Coordination Agreement (MARCA) region. A map depicting all sites described in the text is located in the jacket, inside back cover.

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SYLLABUS

Within the Mid-Continent Area Reliability Coordination Agreement regional area, over 800 hydropower sites were analyzed at the start of the study. After iterative screenings regarding economic, environmental, social, and acceptability criteria, 48 sites remain as those sites having the highest potential for hydropower development. The majority of the hydropower sites are located in the Minnesota-Wisconsin area. The total new capacity and energy which would be added to the regional area, should the 48 projects be developed, would be 1,046 megawatts and 1,654,000 megawatt hours, respectively. Thirty projects are existing hydropower projects which would be considered for expansion; 16 are existing damsites which would be considered for adding hydropower facilities; and 2 projects are undeveloped. The 48 projects would meet 7 percent of the projected peak demand and 2 percent of the projected energy demand for the period 1978 and 1990. As energy costs increase, hydropower sites which were eliminated due to marginal economics and environmental criteria may become cost effective, but the overall study highlights those sites which have the highest potential for development since energy cost increases would make them more attractive for development.

Chapter 1
REGIONAL OBJECTIVES

Our current economy and standard of living have been achieved largely as a result of abundant supplies of low-cost energy. Diminishing availability of traditional primary energy sources, oil and gas, has prompted a national energy policy which emphasizes the development of alternative energy resources and conservation measures. The Mid-Continent Area Reliability Council Agreement Region (MARCA) has the potential for development of new hydropower sources as well as more efficient utilization of existing hydropower projects. However, the full potential may be limited by physical, economic, social, and environmental constraints. Formulation of potential hydropower projects must consider limitations imposed by the existing physical conditions as well as existing land use designations. The overall objectives of this report are to assess institutional, social, economic and environmental factors affecting the development of hydropower, and to identify the potential for development of the region's hydropower resources to help meet the short and long-term energy demands of the Nation. The specific objectives are:

- To analyze and define the region's need for hydropower;
- To assess the potential for increasing hydropower capacity and energy;
- To determine the feasibility of increasing hydropower generation capacity by development of new sites, the addition of generation facilities to existing water resource projects, and increasing the efficiency and reliability of existing hydropower systems;
- To assess the general environmental and socioeconomic impacts of hydropower development; and
- To formulate and develop several alternative plans for the development of the hydropower resource within the region, which would meet regional demand projections and regional constraint criteria.

The regional objective included concentration of studies on conventional hydropower resources and identification of existing pumped storage units, if any.

Chapter 2

EXISTING CONDITIONS (Reliability Council Profile)

2.1 TOPOGRAPHY

The Mid-Continent Area Reliability Council Agreement (MARCA) consists of 400,000 square miles in eastern Montana, the western half of Wisconsin, all of Minnesota, Iowa, Nebraska, and North Dakota, most of South Dakota with the exception of the Black Hills area in the western portion of the state, and a portion of Canada. Since the Canada portion is wholly a canadian utility, it is not represented in this report. The region is characterized by rolling prairie, farmland and glaciated areas dotted with natural lakes and wetlands.

The existing hydrologic areas within the MARCA region consist of portions of the Upper Mississippi River Basin, the Hudson Bay drainage area, the Lake Superior drainage area, and the Missouri River Basin. Existing hydropower plants in each area implicitly characterize, to some extent, the physical, economic, and environmental limitations imposed by the various hydrologic areas.

Table 1-1 indicates the approximate extent of area by State in the MARCA region. Figure 1-1 illustrates the MARCA area in relation to the Nation, and Figure 1-2 shows the hydrologic boundaries within MARCA.

Table 1-1
MARCA AREAL DISTRIBUTION BY STATE

State	Approximate Portion Included	Approximate Area (Square Miles)
Nebraska	All	77,000
North Dakota	All	70,000
Minnesota	All	84,000
Iowa	All	56,000
South Dakota	All except Black Hills area	75,000
Wisconsin	Western one-half	28,000
Montana	Eastern one-fourth	36,000
	TOTAL	426,000

The Missouri River basin area covers about 50 percent of the MARCA area. Within the Missouri River basin, the Great Plains Province forms the heartland of the MARCA region. South and west of the Missouri River, the surface mantle and topography have been developed largely by erosion of a fluvial

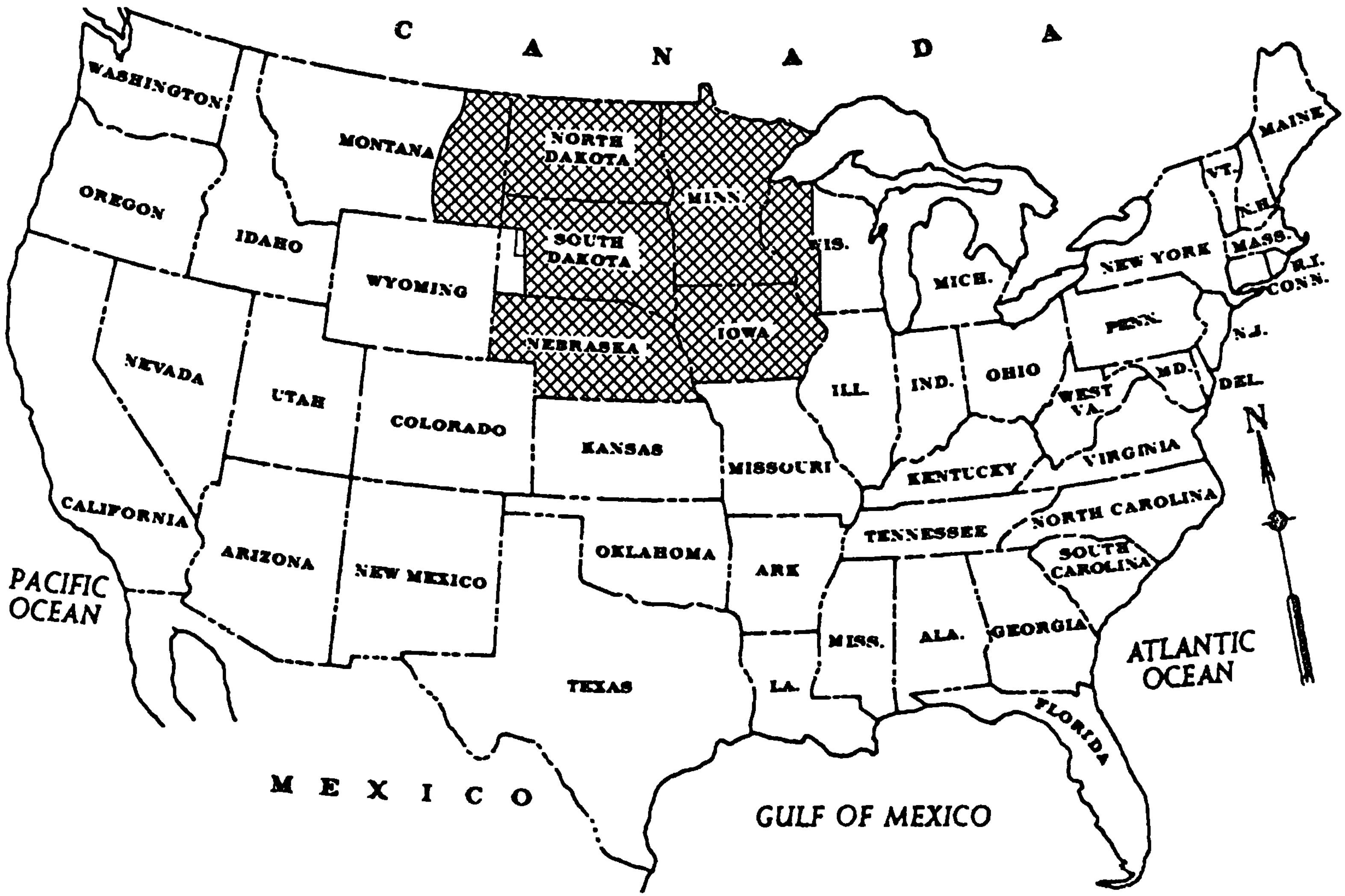


Figure 1-1
MID-CONTINENT AREA RELIABILITY COORDINATION
AGREEMENT (MARCA) MAP

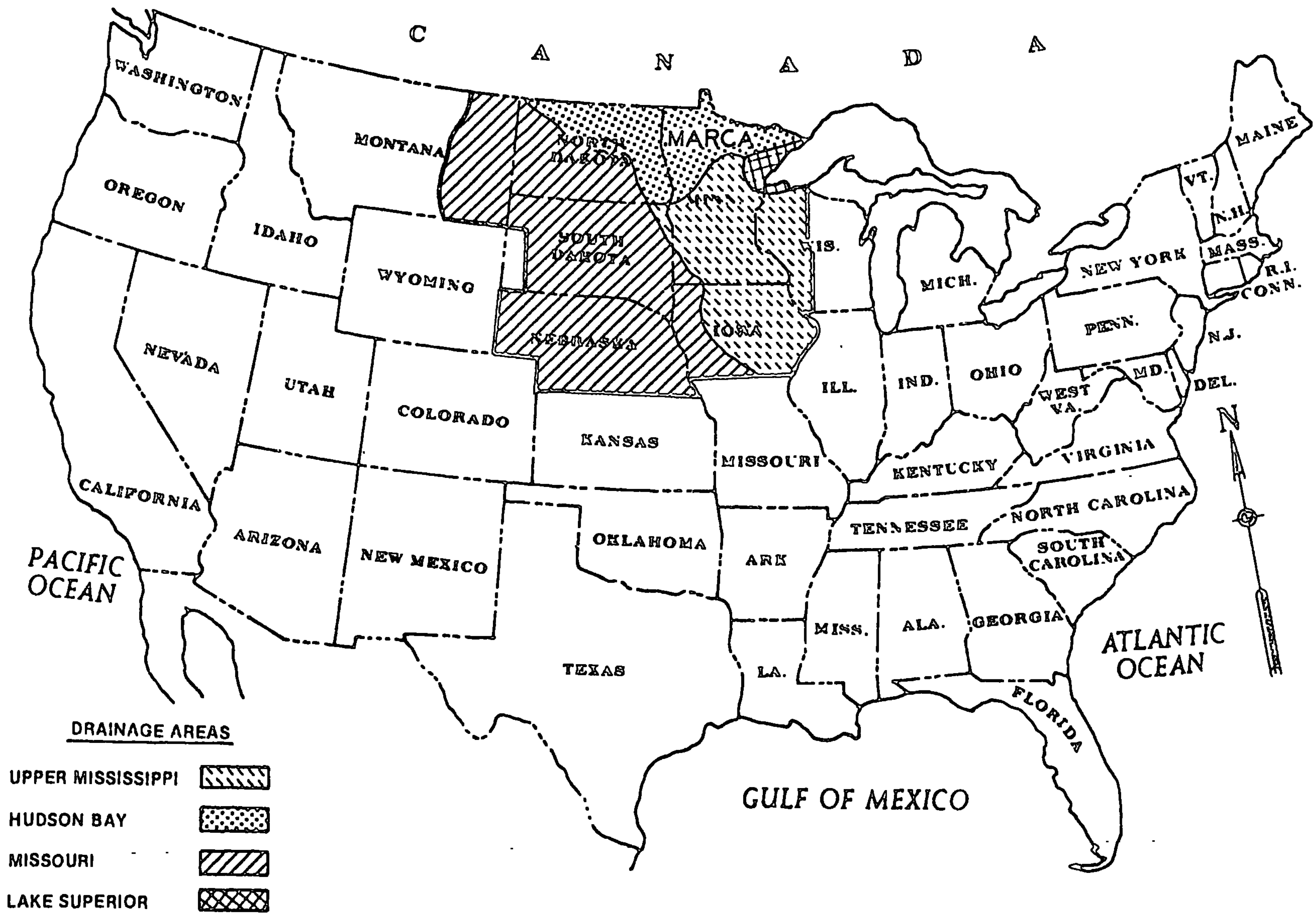


Figure 1.2
MARCA HYDROLOGIC BOUNDARIES

plain extending from the Rocky Mountains. The portion of the Great Plains Province north and east of the Missouri River has been influenced by continental glaciation. The topography was shaped by erosion of the glacial drift and till. The Central Lowlands Province borders the Great Plains Province to the east and extends from a line between Jamestown, North Dakota, and Fairbury, Nebraska, to the Mississippi River drainage divide. This entire area has been developed by erosion of a mantle of drift and till deposited by the continental glaciers. The topography is hilly with an abundance of rainfall. In general, slopes are moderate in North Dakota, South Dakota, Nebraska, and Iowa. Some hilly lands are located along the western tributaries to the Missouri River and along the extreme eastern portion of the Missouri River in Iowa. Slopes are mostly level along the glacial drift lands, the James River in North and South Dakota, and along the Platte River in Nebraska. A unique topographic feature, the Sand Hills, is located in the Great Plains Province in north central Nebraska. This area consists of loose sand dunes stabilized by grasses. There is very little runoff to streamflow but streams in the area have steady flows from groundwater. The moderately sloped lands are found mostly in areas of soft rocks, glacial till, and loess with soils ranging from deep to very deep. The soils in the hilly lands fluctuate from shallow to deep, capable of supporting natural grasses or trees. Poor crop management causes rapid erosion of these soils. Level lands are underlain by alluvium, loess, and glacial drift with soils varying from deep to very deep and erosion is generally low. Most of the land is used for cultivation. Elevations within the Missouri River basin vary between 2300 feet mean sea level (m.s.l.) in northern Montana to about 900 feet m.s.l. near Falls City, Nebraska.

The topography of the Upper Mississippi River basin, which forms the eastern border of MARCA, is a result of the glaciation period. A gently rolling terrain with a progressively less developed drainage system to the north was created. Elevations range from 400 to 2100 feet above m.s.l. Thousands of lakes characterize the surface of the headwater area while the area not covered by glaciation (southern portion) is dissected by streams, creating numerous escarpments and bluffs in the relatively flat-lying sedimentary rocks.

The Hudson Bay basin forms the northern boundary of MARCA in northeastern North Dakota and northwestern Minnesota with the topography ranging from flat to gently rolling hills. Two distinct types of topography are evident - the level plain which flanks the river on both sides and the rougher upland areas east and west of the plain. In the southwest, the plain slopes gently to the upland area elevation, but toward the northwest, the gentle slopes terminate and begin to rise abruptly. This area is known as the Pembina Escarpment. On the east, the valley is bounded by a hilly area that merges into lakes and swamps in the upland area. In the northeast, the plain is level and includes extensive swampland. Most of the basin lies between 800 and 1600 feet above m.s.l.

The Lake Superior drainage area forms the extreme northeast corner of MARCA and is typified by round hills with deep cut valleys and level to gently undulating plains, with the exception of the steep slopes northeast of

Duluth, Minnesota. Soils are low in fertility and are poorly drained. The proportion of land in forests is high. Hardwood forests of beech, birch, maple, and aspen typify the Wisconsin area while hardwood and softwoods characterize the Minnesota portion.

2.2 HYDROLOGIC CONDITIONS

The hydrologic conditions of climate, precipitation, and runoff within the MARCA area can best be described by drainage basin.

Missouri River Basin

The Missouri River basin experiences weather known for its fluctuations and extremes. Winters are long and cold over much of the basin while summers are fair and hot. Precipitation is in the form of snowfall from November through March, while in July and August thunderstorms are prevalent. Often the rainfall is localized, with high-intensity. Prolonged droughts may be interspersed with periods of abundant precipitation. The annual precipitation within the plains varies between 12 and 24 inches. Temperature extremes range from winter lows of minus 60° F in Montana to summer highs of up to 120° F in Nebraska. Winds are a rule rather than an exception in the plains area with average velocities in excess of 10 miles per hour.

Upper Mississippi River Basin

The climate of the upper Mississippi River basin varies from the northern to the southern extremities. The northern two-thirds of Minnesota and all of Wisconsin, except the southwest corner, have cold humid winters with comparatively cool summers. Southern Minnesota, southwest Wisconsin, and Iowa have cold humid winters and hot summers. There is, generally, more precipitation in the spring and summer months than in the fall and winter months. Average annual precipitation is about 32 inches, with 8 inches as surface runoff and 24 inches as evaporation and transpiration. Snowfall varies from 96 inches in Wisconsin to 8 inches near the southern portion of the basin. January has the lowest temperature and July the highest. Average annual temperature ranges from 40° F in the northern area to 59° F in the southern portion. Months of highest runoff in both the Mississippi River and Missouri River basins are generally March through June. March and April streamflows are augmented by melting snow. The annual runoff as a percentage of annual precipitation varies between 5 and 40 percent.

Hudson Bay Drainage

The climate of the Hudson Bay basin is called temperate with temperatures ranging above 114° F in the summer to minus 54° F in the winter. Precipitation varies from 6 to 29 inches in the Souris River basin and from 16 to 25 inches in the Red River of the North basin. Because of the impermeable nature of the soils, groundwater is a very small contribution to streamflow. Runoff is at a maximum in the spring and at a minimum during the winter. April, May and June have large amounts of runoff with April having 41 percent.

Lake Superior Drainage

The climate of the Lake Superior drainage area is influenced by Lake Superior where air temperatures are moderated and winds and humidity are high. The average monthly precipitation increases from a winter low of 1.6 inches to a summer high of 3.3 inches. Annual precipitation averages about 33 inches. Spring and summer precipitation is greater inland while winter precipitation is greater over the coastal areas. Average monthly temperatures vary from lows of 13° F in January to highs of 65° F in July. The average annual runoff is about 12 inches, with the months of April and May having the highest runoff values.

2.3 ECONOMICS OF AREA (Present and Future)

Since portions of seven states make up the MARCA region and since economic data are commonly aggregated along state boundaries, highlights of each state's economy are discussed as a prelude to any discussion of population, employment, and earnings within the MARCA region.

Nebraska

Nebraska is one of the leading agricultural and livestock states in the Nation. Ranching is dominant in the west with general farming prevailing in the east. Corn is the most important crop, followed by wheat, oats, barley, rye, alfalfa, potatoes, sorghum, soybeans, and sugar beets. Approximately 30 percent of the cultivated acreage in the State is utilized for corn crops. The largest industry is food processing with flour, dairy, and meat products prominent. The manufacturing of durable goods includes the production of electrical machinery, farm equipment, metal and prefabricated buildings, automotive parts, and energy conversion systems. Aside from farming and industry, Nebraska produces large amounts of minerals. Non-metallic minerals such as clay, gem stones, limestone, sand, gravel, and pumice account for over half of the State's mineral production. Crude petroleum, natural gas and natural gas liquids are also produced in the State.

Iowa

Iowa is known for its rich soil and high crop yields; approximately 20 percent of all the corn grown in the United States comes from this State. It ranks second in the Nation in soybean production and also produces large crops of oats and forage. Other produce products grown in the State include cantalopes, sweet potatoes, asparagus, watermelons, and apples. One-fifth of the Nation's hogs and one-fourth of the Nation's cattle are sent through Iowa's livestock markets. Dairy cattle, poultry and sheep are raised throughout the State. In 1977 more than 4,000 manufacturing firms brought an annual return of over $10.5 billion into the State. The primary industry is the processing of agricultural and livestock products. Of the minerals available in Iowa, gypsum is the most important. Coal, sandstone, gravel, and cement production also add to the State's economy.

North Dakota

Agricultural production related industry and services and the production of minerals comprise most of North Dakota's economy. The State leads the Nation in the production of rye, barley, and flax and is second only to Kansas in wheat production. Other important crops include oats, corn, alfalfa, sweet clover, potatoes, sugar beets, sunflower seeds, pinto beans, and soybeans. As a major livestock region, the State raises cattle, sheep, hogs, horses, and poultry. Most of the State's industry stems from the processing of agricultural products. Oil and coal are major resources of this State; more than 1,970 wells produced 59,000 barrels of oil a day in 1977. The extensive lignite deposits, low grade coal, are mined and utilized for power production in three large fossil-fuel powerplants located in the State.

South Dakota

Agriculture, mineral production and tourism comprise most of South Dakota's economy. Leading crops include corn, wheat, oats, rye, soybeans, barley, hay, sunflowers, flaxseed, bluegrass, and alfalfa. Ranching is found throughout the State with cattle, hogs, sheep, and horses as primary livestock. The State's principal industries - food processing, meat packing, and flour milling - stem from this agricultural development. The most important mineral resource in South Dakota is the gold mined in the Black Hills; these gold mines yield millions of dollars a year. Other mineral resources important to the State include beryl, feldspar, lithium, mica, carnotite ores, silver, clays, low-grade manganese ore, lignite coal, quartzite, and granite.

Montana

Montana is primarily an agricultural State with lumbering and wood products becoming a fast-growing area of economic activity. The major crops include winter wheat followed by hay, sugar beets, beans, corn, oats, barley, and potatoes. The growing wood industry includes production of products such as boxes, paper pulp, plywood, sash, doors, and prefabricated buildings. Mining is still important to the economy and a large portion of this mineral wealth is processed in the state. Of the 58 minerals mined in the state, copper, silver, gold, lead, zinc, manganese, oil, natural gas, coal, phosphate, and chromite are most important. Large herds of cattle and sheep are also raised in Montana.

Minnesota

Since World War II, industry, commerce, and services have surpassed farming as major contributors to this State's economy. Minnesota's leading industries include the processing of livestock and flour milling. In addition, the production of tapes, abrasives, computer and electronic controls, plastics, construction and farm machinery, sporting goods, textiles, clothing, and pottery are important. Minnesota ranks first in the Nation in the production of butter, dried milk, oats, timothy seed, sweet corn, and turkeys; second in hay, American cheese, and dairy cattle; and third in flaxseed, peas, milk, rye, and red clover seed. The State is also a primary supplier of wild rice.

One-third of the State's area is classed as forest land; thus, lumbering has become an important industry in this State. Northern Minnesota contains the richest source of iron ore in the United States. The State ranks third in the Nation in the production of granite. Extensive deposits of travertine, limestone, and clay also contribute to the State's economy.

Wisconsin

Manufacturing is the largest single contributor to Wisconsin's economy. Goods produced in this State exceed $25 billion annually. Heavy metalworking industries which produce engines, construction machinery, and farm equipment are the largest. Paper and paper products are important throughout the State, while large auto assembly and shipbuilding plants are important to the eastern part of the State.

Wisconsin leads the Nation in the production of milk, condensed milk, and cheese, and ranks second in the manufacture of butter. Large breweries are located throughout the State. Agriculture is important to the State's economy with annual farm income averaging about $2.5 billion. Major crops include green peas, sweet corn, snap beans, beets, cranberries, cabbage, lima beans, and carrots. Apples and cherries are raised throughout the State and processed in eastern Wisconsin. Mink ranching is also popular with yields of about $25 million in pelts per year. Sand and gravel are the most valuable minerals in the State, followed by granite, dolomite, zinc ore, clays, and iron.

MARCA Population and Economic Projections

An analysis of the population and earning trends within the MARCA region was published in a report entitled "The Magnitude and Regional Distribution of Needs for Hydropower, The National Hydropower Study" by Harza Engineering Company in April 1979. The report was prepared for the Institute for Water Resources. The projections for the MARCA region were obtained by aggregating the data available for the Bureau of Economic Analysis (BEA) economic areas which approximate the MARCA region. These projections were based on 1972 Office of Business and Economic Research Projections, Series E (OBERS), published by the U.S. Water Resources Council.

A closer inspection of the Harza report indicated the BEA areas used to best represent the MARCA region do not coincide entirely with the MARCA boundaries. Therefore, the BEA areas were reaggregated to correspond with the MARCA area and the economic data were adjusted. Figure 2-1 shows the differences between the two BEA areas. Further analysis of the Harza data indicated that application of the most recent Bureau of Census data (1979 estimates) would increase the MARCA population by 2 to 3 percent. As a result of both adjustments, the MARCA population figures would be adjusted by 6 to 7 percent above the Harza estimates. Table 2-1 shows projections of economic data to the year 2000. The population within MARCA is expected to increase from 10,383,000 in 1970 to 11,810,800 in 2000. This would represent an average annual growth rate of 3.8 percent. In the interest of interregional consistency within the National Hydropower Study, the Harza electrical demand projections presented in Chapter 4 were used throughout this report.

Table 2-1
MARCA EMPLOYMENT, INCOME, AND ECONOMIC PROJECTIONS

	1970	1980	1985	1990	2000
Population	10,383,300	10,771,000	11,057,800	11,357,100	11,810,800
Employment	4,044,300	4,676,400	4,824,000	4,977,700	5,469,800
Tot Pers Inc 1/	33,734,100	49,251,800	57,685,300	67,130,900	93,433,500
Tot Earnings 1/	26,294,400	37,863,900	44,174,600	51,799,968	70,994,900
Per Cap Inc	3,249	4,573	5,217	5,911	7,912

1/ In $1,000 Constant 1967 Dollars

Nearly 30 percent of the current MARCA population resides within five large metropolitan areas with populations of 200,000 persons or more. These areas are:

Minneapolis-St. Paul, Minnesota and Wisconsin
Omaha, Nebraska
Davenport-Rock Island - Moline, Iowa and Illinois
Des Moines, Iowa
Duluth-Superior, Minnesota and Wisconsin

The Minneapolis-St. Paul urban area comprises about 60 percent of the combined population of all five areas followed by Omaha at 16 percent. The remaining three urban areas represent 10 percent and under.

About 32 percent of the MARCA population reside in Minnesota, the State with the highest concentration of people in the region. Iowa has an estimated 23 percent of the total MARCA population followed by 19 percent for the portion of Wisconsin in MARCA, and 13 percent in Nebraska. The States of South and North Dakota and Montana combined to make up the remaining 13 percent.

MARCA's 1970 population comprised about 5 percent of the Nation's total. By 2000, projections indicate a reduction to 4.5 percent, suggesting a growth rate slightly less than that for the Nation. Just as the region's projected share of the Nation's population is projected to drop by 10 percent, so is the region's share of national earnings. The Table 2-1 value of $26.3 million in total earnings for 1970 represented 4.7 percent of total national earnings; the projection for the year 2000 of $71.0 million represents only 4.3 percent of the Nation's total -- once again about a 10 percent loss of ground. Unless trends take place to override existing projections, the MARCA area will decline slightly in its share of national economic growth during the next 20 years.

Table 2-2 shows the shifts in economic activity projected by OBERS for the 30-year period from 1970 to 2000. A glance at the table shows agriculture will have a 50 percent decline in earnings, with the largest earning increase in services and Government.

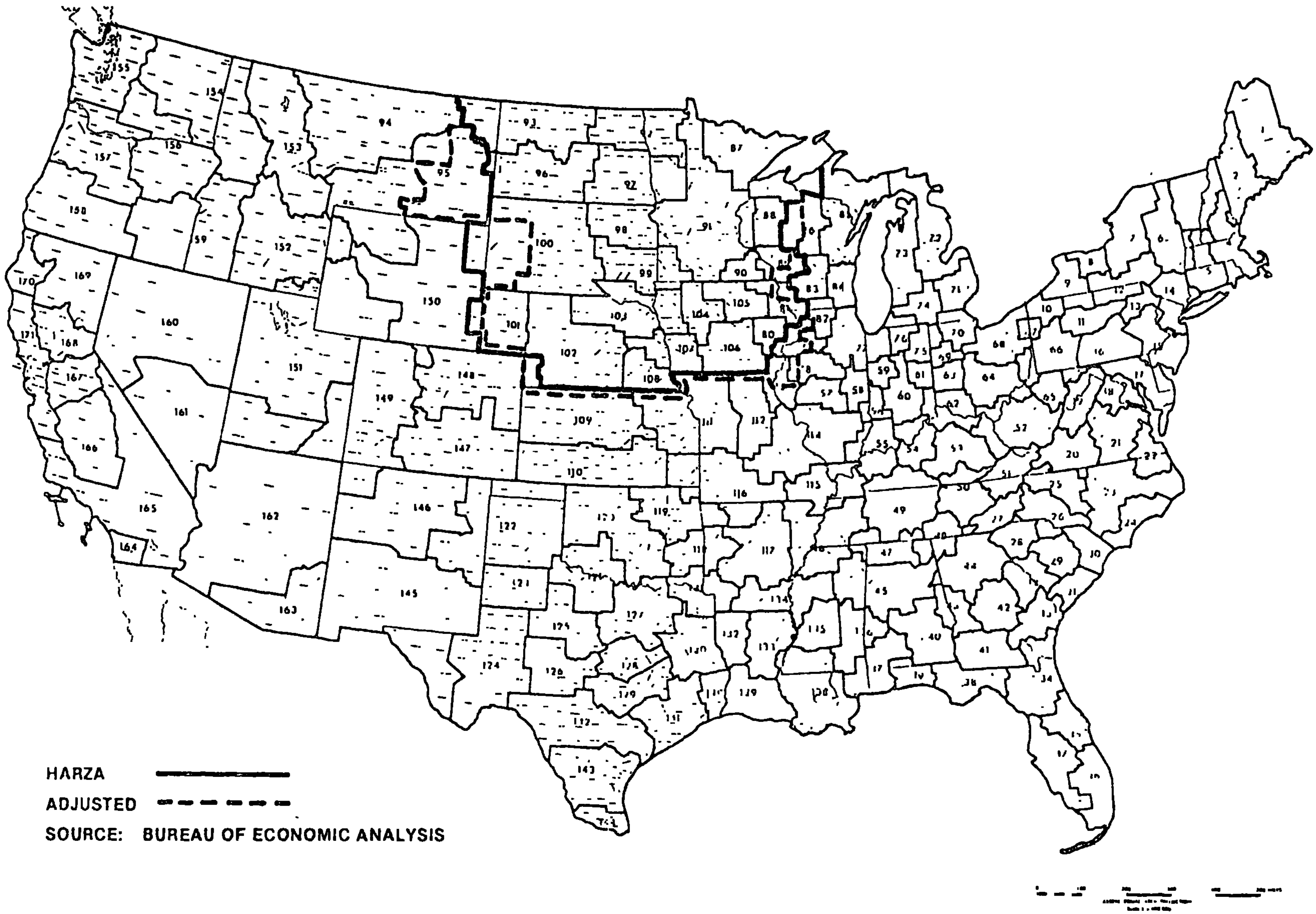


Figure 2-1
BUREAU OF ECONOMIC ANALYSIS ECONOMIC AREAS

Table 2-2
ECONOMIC INDICATORS

Sector	Percent Sector Earnings 1970	2000
Agriculture	13.2	6.5
Mining	0.8	0.4
Construction	6.2	5.9
Manufacturing	21.6	21.4
Transportation Utilities	6.9	6.6
Trade	17.7	15.8
Finance	4.5	5.8
Services	13.3	19.7
Government	15.8	17.9
	100.0	100.0

2.4 MAJOR ENERGY USERS

The MARCA region covers the upper-midwestern part of the United States and the province of Manitoba in Canada. The MARCA members serve 3.6 million customers and a population of about 10 million. In the past, the area presently represented by MARCA included three formal power pools: Upper Mississippi Valley Power Pool with 13 members, the Iowa Power Pool with 6 members, and the Missouri Basin System Group with 4 major members. An informal power pool, the Mid-Continent Area Power Planners (MAPP) was formed primarily to develop broad plans for expansion of generation and to reduce the cost and improve the reliability of electric service. In 1968, MAPP recognized the need for a formal organization to provide an overview of the planning and operating activities with respect to reliability in the region; therefore, the larger utilities organized MARCA. MARCA presently has a membership of 22 large utilities. The Manitoba Hydro Electric Board in Canada is an associate member of MARCA but is not represented in this report since it is wholly a Canadian utility.

The principal energy distributors in the MARCA region include six major electric utilities. These utilities marketed approximately 52 percent of the total peak demand of 17,549 megawatts (MW) in July 1977. Table 2-3 gives the annual energy, peak demand, and load factor for each utility. In 1977, the total net energy sold in MARCA was 85,738 gigawatt hours (GWH). Table 2-4 presents the percent of energy consumption by consumer categories for the representative utilities in MARCA. It indicates the major users of electrical energy within MARCA are industry and rural and residential users, accounting for 58 to 74 percent of the total use. Commercial uses account for between 9 and 30 percent of the overall energy consumption. Hospitals, and other public uses account for between 3 and 31 percent of the total. As the land changes, the distribution would change somewhat, depending on the overall characteristics relating to weather and geographical location. In

Table 2-3
ANNUAL ENERGY, PEAK DEMAND, AND LOAD FACTOR BY UTILITY 1977

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

1977, one utility (Northern States Power Company) accounted for about 25 percent of the peak MARCA demand and about 24 percent of MARCA's annual energy use.

2.5 OPERATING PROCEDURES WITHIN THE RELIABILITY COUNCIL AREA

The MARCA system utilizes a set of standards designed to measure the ability of the system to withstand a broad spectrum of contingencies affecting power system reliability. The standards constitute an effective and practical means of simulating stress to the MARCA System to predict its ability to function with uncontrolled, area-wide power interruptions, even under quite severe conditions. A periodic testing of the overall projected system in accordance with criteria formally documented by these standards is made. The standards include a set of contingencies referred to as probable disturbances or extreme disturbances which the overall system is to be capable of withstanding without interruption of load due to instability or cascading. The system design is intended to minimize the spread of any interruption that might result from such extreme disturbances. A MARCA Design Review Committee was established for the purpose of reviewing system generation and transmission plans (additions and retirements) to assure compliance with these standards. In all cases, system additions must maintain or improve the MARCA system operation, reliability, and transfer capability.

Table 2-4
ENERGY CONSUMPTION BY CONSUMER CATEGORIES 1977
(PERCENT OF TOTAL)

Company	Rural and Residential	Commercial	Industrial	Others	Total
Interstate Power Co.	30.3	20.5	39.7	9.5	100.0
Iowa Electric Light & Power Co./ Central Iowa Power Cooperative1/	37.6	25.1	29.4	7.9	100.0
Iowa Power & Light Co.	38.2	23.9	35.3	2.6	100.0
Lake Superior District Power Co.	30.6	19.3	38.7	11.4	100.0
Minnesota Power & Light Co.	10.9	8.6	55.1	25.4	100.0
Northern States Power Co.	24.3	11.5	33.7	30.5	100.0
Omaha Public Power District	32.9	30.3	25.0	11.8	100.0
Otter Tail Power Co.	35.9	45.42/		18.7	100.0

1/ Percentages listed are for 1976.

2/ Percent shown is for both commercial and industrial use.

SOURCE: 1977 Annual Reports of the above listed utilities.

Chapter 3
EXISTING ENERGY SYSTEMS

3.1 EXISTING ENERGY SYSTEMS EXCLUDING HYDROPOWER

Nuclear

Nuclear plants provide a substantial portion of the total power generated in the MARCA area, ranking second only to fossil generation. The Minnesota-Wisconsin subarea provides 43.4 percent of the total nuclear generation in MARCA followed by 33.3 percent in Nebraska and 23.3 percent in Iowa.

Type of Energy

The nuclear power generated in MARCA is used solely for base load energy. Base load energy is generally defined as the minimum load over a specified period of time. Base load units have high efficiency and are suitable primarily for continuous operation at as nearly constant load as possible. The total base load energy provided by nuclear plants in 1978 was approximately 27 percent.

Magnitude

In the summer of 1979, six existing nuclear generating stations provided a capability of 3655 MW which represented 15 percent of the total generation capability in the MARCA area. This was a decrease from the 1977 winter generating capability of 3750 MW or 17 percent of the total. The six projects produced 25,398 million kilowatt-hours in the winter of 1978. This represented about 26.9 percent of the MARCA total net generation in 1978.

Future Potential

According to utility forecasts, no new nuclear generating units are scheduled for addition during the period of summer 1979 to summer 1988. An additional 29 MW of nuclear generating capability is scheduled for this period due to an upgrade of a nuclear unit in Nebraska. Nuclear power generation is expected to increase from 25,398 million killowatt-hours in the summer of 1978 to 34,685 in the summer of 1988. Despite this increase, the percent of nuclear power compared to the total MARCA power generation is expected to decrease from 26.9 percent in 1978 to 21.5 percent in 1988. Table 3-1 shows the MARCA projected increases in nuclear power generation during the period of summer 1978 to summer 1988.

Impacts

The major impacts associated with nuclear power generation concern radioactive releases and wastes, and thermal impacts caused by the release of cooling

Table 3-1
PROJECTED NET GENERATION BY SOURCE
(MILLIONS OF KILOWATT-HOURS)

	1978 (actual)	1979	1980	1982	1984	1986	1988
Nuclear	25,398	27,964	26,568	26,254	26,290	31,467	34,685
Oil	1,720	1,330	1,460	1,447	1,852	2,128	1,566
Coal	50,183	61,478	69,174	82,231	92,214	101,738	112,718
Gas	1,523	867	701	414	29	23	23
Net generation excluding hydropower	78,824	91,639	97,903	110,346	120,385	135,356	148,992
PERCENT OF NET GENERATION Excluding Hydropower							
Nuclear	32.22	30.52	27.14	23.79	21.84	23.25	23.28
Oil	2.18	1.45	1.49	1.31	1.54	1.57	1.05
Coal	63.67	67.08	70.65	74.52	76.60	75.16	75.65
Gas	1.93	.95	.72	.38	.02	.02	.02

1/ Based on 1979 information from Annual Electric Power Survey. Recent information indicates projections of nuclear energy may be overstated.

water. Small quantities of radioactive gaseous and liquid wastes are routinely released from nuclear plants. The gaseous waste is released to the atmosphere through plant stacks and the liquid waste is diluted and released to the water body supplying the plant. The remaining solid waste is collected and stored to await shipment to off-site burial grounds. The standards for a nuclear plant are quite rigid, the controlled waste releases must not exceed limits set by Federal Safety Standards. Despite these standards, there is concern by some that accidents could occur releasing radiation into the atmosphere. The gaseous wastes released from nuclear reprocessing plants contain radioactive isotopes which, in small quantities, are not harmful and cannot concentrate to a great degree. Techniques are being studied and developed to minimize these impacts. The heated discharges of water used for cooling in nuclear power plants also cause concern. Because nuclear plants are less efficient than fossil-fueled plants more heat is discharged into the supplying water body. Changes in the temperature of the water, impingement, and entrainment may affect the population of fish, plants and other aquatic organisms found in the water.

Ownership

As of January 1, 1978, the majority of nuclear power generated in MARCA was by investor owned electric utilities followed by public power districts and power cooperatives. Table 3-2 shows the MARCA ownership distribution of nuclear power.

Table 3-2
DISTRIBUTION OF OWNERSHIP FOR NUCLEAR GENERATING UNITS
(AS OF JANUARY 1, 1978)

	Capability MW	Percent of Total
Investor owned	1990	53.3
Public power districts	1235	32.9
Cooperatives	516	13.8
TOTAL	3750	100.0

OIL

Existing combustion turbines in the MARCA area use oil as fuel. In recent years oil has become expensive and in short supply. For these reasons, expected increases in oil as a fuel for power generation will be very moderate. In the summer of 1979, the Minnesota-Wisconsin subarea provided 46.5 percent of the total oil generated power in the MARCA region followed by 27.4 percent in Iowa, 15.8 percent in Nebraska and 10.3 percent in the Dakotas - Montana subarea.

Type of Energy

Energy generated by oil provides most of the peaking energy and a small portion of the intermediate energy in MARCA. The intermediate load is characterized by a rapid increase in demand during the morning and a rapid decrease in late afternoon, remaining fairly constant in between. These units are usually less efficient than base load units and have a moderate ability to supply changing loads. Peak load is generated to meet the peak demand over a specific period of time. Peaking units generally are less efficient than intermediate units and are designed to respond to rapid load changes.

Magnitude

Existing combustion turbine generating capability in the MARCA area totaled 3727 MW in the winter of 1977. This represented 17.1 percent of the MARCA capability during that winter. In the summer of 1979, the capability of oil-generated power was decreased to 2840 MW or 11.6 percent of the MARCA total. During the winter of 1978 combustion turbines provided 1,720 million killowatt-hours, 1.8 percent of the total MARCA net generation. The gross oil requirement of MARCA in 1978 was 4,024,000 barrels.

Future Potential

According to utility forecasts, during the period of summer 1979 to summer 1988, one additional combustion turbine generating unit is expected. The Dakotas - Montana subregion is expected to add 28 MW in 1985, bringing the total MARCA oil generation capability to 2868 MW in 1988. The combustion turbine generation in MARCA is expected to decrease from 1720 million killo-watt-hours in the winter of 1978 to 1566 million kilowatt-hours in 1988. This represents a decrease in total MARCA net generation from 1.8 percent in 1978 to 1.0 percent in 1988. Table 3-1 shows the projected decrease in MARCA oil generation during this period.

Impacts

The major impact associated with oil power generation is thermal air pollution. Air pollution is a major concern of oil power plants. Fuel oil contains less than two-tenths of a percent of incombustible material which creates air pollution. The two main variables affecting air pollution from oil plants is the ash content of the fuel and also the method of firing the fuel. Particulate matter emitted from oil fired plants consists of sulfates and cenospheres (partially burned droplets of oil). The problem of particu-late emissions can be largely solved by collectors and electrostatic precipi-tators.

Ownership

As of January 1, 1978, investor owned electric utilities comprised most of the ownership of MARCA oil generation facilities, followed by public power districts, cooperatives, and municipal electric utilities. Table 3-3 shows the distribution of this ownership.

COAL

Coal-fired plants provide the greatest single source of generation in the MARCA area, and will continue to do so in the near future because of the

Table 3-3
DISTRIBUTION OF OWNERSHIP FOR OIL GENERATING FACILITIES
(AS OF JANUARY 1, 1978)

	Capability (MW)	Percent of Total
Investor owned Elec. Utilities	2626	70.5
Public Power Districts	592	15.9
Municipal Elec. Utilities	129	3.4
Cooperatives	380	10.2
TOTAL	3727	100.0

availability and low cost of coal. The Minnesota-Wisconsin subarea provides 45.5 percent of the total coal power generation in MARCA, followed by 25.8 percent in Iowa, 16.5 percent in Nebraska, and 12.2 percent in the Dakotas-Montana subarea.

Type of Energy

Coal-fired plants are the primary suppliers of both base load and intermediate energy in MARCA. Approximately 75 percent of the base load and about 77 percent of the intermediate load in MARCA is supplied by coal-fired plants. All of the coal-fired plants are classified as either base or intermediate, although some intermediate cycling coal plants are capable of operating near the top of the load curve.

Magnitude

In the winter of 1977, the MARCA coal generation capability was 11,126 MW, which represents 50.9 percent of the total MARCA generation capability. In the summer of 1979, this capability had increased to 14,549 MW or 59.3 percent of the total. During the winter of 1978 coal generation was 50,183 million kilowatt-hours; this represented 53.2 percent of the total MARCA net generation. The gross coal required for the MARCA region in 1978 was 33,012,000 tons.

Future Potential

According to utility forecasts, coal generation is projected to show the most increase in the MARCA region during the 1979 to 1988 period. Seventeen new coal units totaling 7,792 MW are scheduled for completion during this period. During this same period of time, 627 MW of coal generation are scheduled for retirement. The total coal generation capability projected for 1988 is 21,714 MW. Generation in millions of killowatt-hours is projected to increase from 50,183 in 1978 to 112,718 in 1988. The percent of coal generation compared to MARCA net generation excluding hydropower is expected to increase from 64.0 percent in 1978 to 76.0 percent in 1988. Table 3-1 shows coal generation increases during this period. The amount of coal required for MARCA is expected to increase from 33,012,000 tons in 1978 to 74,251,000 tons in 1988, representing a compound growth rate of four percent annually.

Impacts

The impacts associated with coal-fired generation are nearly the same as those for oil-thermal air pollution, and aesthetics. The coal used in power plants contains from 5 to 20 percent ash as compared to the two-tenths percent contained in oil. As a result, the major concern associated with coal plants is thermal air pollution and the possible effects on the atmosphere of power plant emissions. Coal contains sulfur in nature with some coal deposits having less sulfur content than others. During the combustion process, about 95 percent of the sulfur is oxidized into sulfur dioxide (SO_2) and sulfur trioxide (SO_3). Sulfur dioxide coupled with nitrous oxides are considered health hazards when certain levels are reached in the atmosphere. Coal contains incombustible materials known as particulate matter or fly ash. During combustion, the particulate matter is carried into the atmosphere in the form of fly ash which is a combination of silica, alumina, and iron oxide. However, the problem of particulate emissions from stacks of coal-fired electric plants can be largely reduced through the installation of mechanical collectors and electrostatic precipitators which remove 97 to 99 percent of the particulates. The disposal of fly ash is a primary concern due to the potential of surface and ground water contamination.

Ownership

Most of the coal generating facilities in MARCA are owned by investor-owned electric utilities followed by cooperatives and then public power districts. Table 3-4 shows the distribution in the MARCA region.

Table 3-4
DISTRIBUTION OF OWNERSHIP FOR COAL-FIRED GENERATION PLANTS
(AS OF JANUARY 1, 1979)

	Capability (MW)	Percent of Total
Investor Owned Electric Utilities	7,139	64.2
Cooperatives	3,030	27.2
Public Power Districts	957	8.6
TOTAL	11,126	100.0

GAS

Gas-fired generation facilities provide only a small percentage of the total power generated in MARCA. These plants are primarily used in the Minnesota-Wisconsin and Dakotas-Montana regions. In 1979, 60.6 percent of the MARCA gas generation was produced in these regions, followed by 21.9 percent in Iowa and 17.5 percent in Nebraska.

Type of Energy

Gas-fired generation provides an extremely small portion of the total energy in MARCA. It is used primarily for peaking energy and provides less than 1 percent of that energy.

Magnitude

Gas generation provided a capability of 257 MW, only 1.2 percent of the MARCA net generation in the winter of 1977. It increased to 315 MW or 2 percent of the total MARCA capability by the winter of 1979. In the winter of 1978, gas generation provided 1,523 million kilowatt-hours or 1.6 percent of total net generation in MARCA.

Future Potential

According to utility forecasts, there are no new gas generation additions committed or proposed for the MARCA area during the 1979 to 1988 period. Gas generating capability will actually decrease because of scheduled retirements of 25 MW. Thus, the total generating capability in 1988 is projected to be 290 MW, with energy generation projected at 23 million kilowatt-hours or .01 percent of the MARCA net generation. This is a decrease from 1,523 million kilowatt-hours or 1.6 percent of the total from 1978. Table 3-1 shows the MARCA projection in gas generation for the 1978-1988 period.

Impacts

The major impacts for gas generation plants are essentially the same as oil generation plants. These include thermal air pollution and aesthetics. However, gas is essentially ash-free and emissions of particulate matter from gas plants are principally the result from dust particles in the gas. The sulfur content in gas can be easily removed thereby providing much cleaner plants with considerably less particulate matter than coal and oil plants; therefore, the air pollution problem is not as serious for gas-fired plants as it is for coal-fired plants.

Ownership

Nebraska Public Power District owns 61 percent of all gas generation facilities in MARCA. Investor-owned electric utilities own the remaining 39 percent. Table 3-5 shows the distribution of ownership of MARCA gas generating facilities.

MARCA SOURCE GENERATION SUMMARY

According to utility forecasts, the total net generating capability excluding hydropower planned in the MARCA area is projected to increase by 7197 MW during the 1979-1988 period. The addition of 7792 MW of coal-fired generation makes up the greatest portion of this increase. Nuclear and combustion turbine generation will increase by 29 MW and 28 MW, respectively.

Table 3-5
DISTRIBUTION OF OWNERSHIP FOR GAS GENERATING FACILITIES
(AS OF JANUARY 1, 1978)

	Capability (MW)	Percent of Total
Public Power District	158	61.0
Investor-Owned Electric Utilities	99	39.0
TOTAL	257	100.0

The retirement of 627 MW of coal-fired generation and 25 MW of diesel generation are scheduled during the same period. Figure 3-1 shows the distribution of MARCA generation by source for the years 1979 and 1988. Figure 3-2 shows locations of existing and future generating plants 70 MW or larger in the MARCA area, exclusive of additional hydropower sites identified in this study.

3.2 ROLE OF HYDROPOWER WITHIN EXISTING SYSTEM

Conventional hydropower currently plays an important role in the MARCA generation system. About 12.2 percent of the total 1979 summer generating capability was provided by hydropower. As of January 1, 1979, there were 57 hydropower plants in the MARCA system. The plant capabilities range from less than 1 MW to more than 650 MW. The majority of MARCA hydropower facilities provide a capability of less than 30 MW each. However, there are eight large Federal hydropower plants which provide approximately 84 percent of the MARCA hydropower capability. Of the eight Federal hydropower plants, six located on the Missouri River, were constructed and are operated by the Army Corps of Engineers. The remaining two are Water and Power Resources Service projects - one on the Missouri River and one on the Big Horn River. Although the Water and Power Resources Service hydropower project, Canyon Ferry on the Missouri River, is considered as part of the MARCA capability; it is physically located in the WSCC reliability area. Therefore, an analysis of this site will be in the WSCC regional report. About 84.2 percent of the total MARCA hydropower generating capability is located within the Dakotas and Montana with the remaining 11.6 percent, 4.1 percent, and 0.1 percent located in Minnesota-Wisconsin, Nebraska, and Iowa, respectively.

There are no hydropower additions or retirements scheduled for MARCA during the 1979-1988 period; however, a slight decline in hydropower capacity during this period is projected. This reflects the conservatism in forecasts which anticipate future water supplies and capacity to be less than experienced in the good water year of 1978.

Magnitude

According to utility reports, the 1979 summer hydropower capability was 2970 MW. The total 1978 hydropower generation in the MARCA area was 15,495 million kilowatt-hours, representing 16.5 percent of the total MARCA net generation. Utilities indicate by 1988, hydropower generation is expected to decline to 7.5 percent of the net total, or 12,074 million kilowatt-hours.

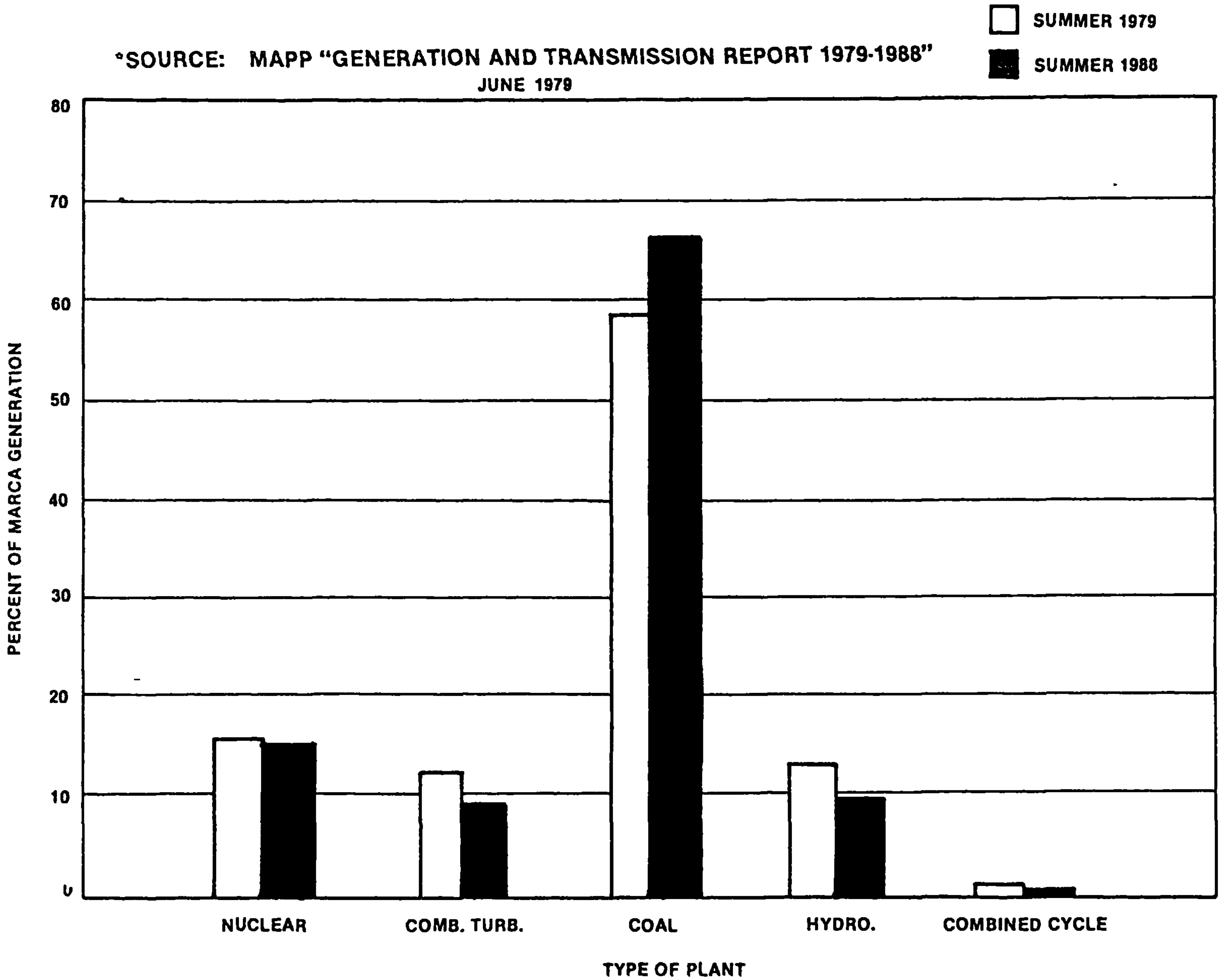
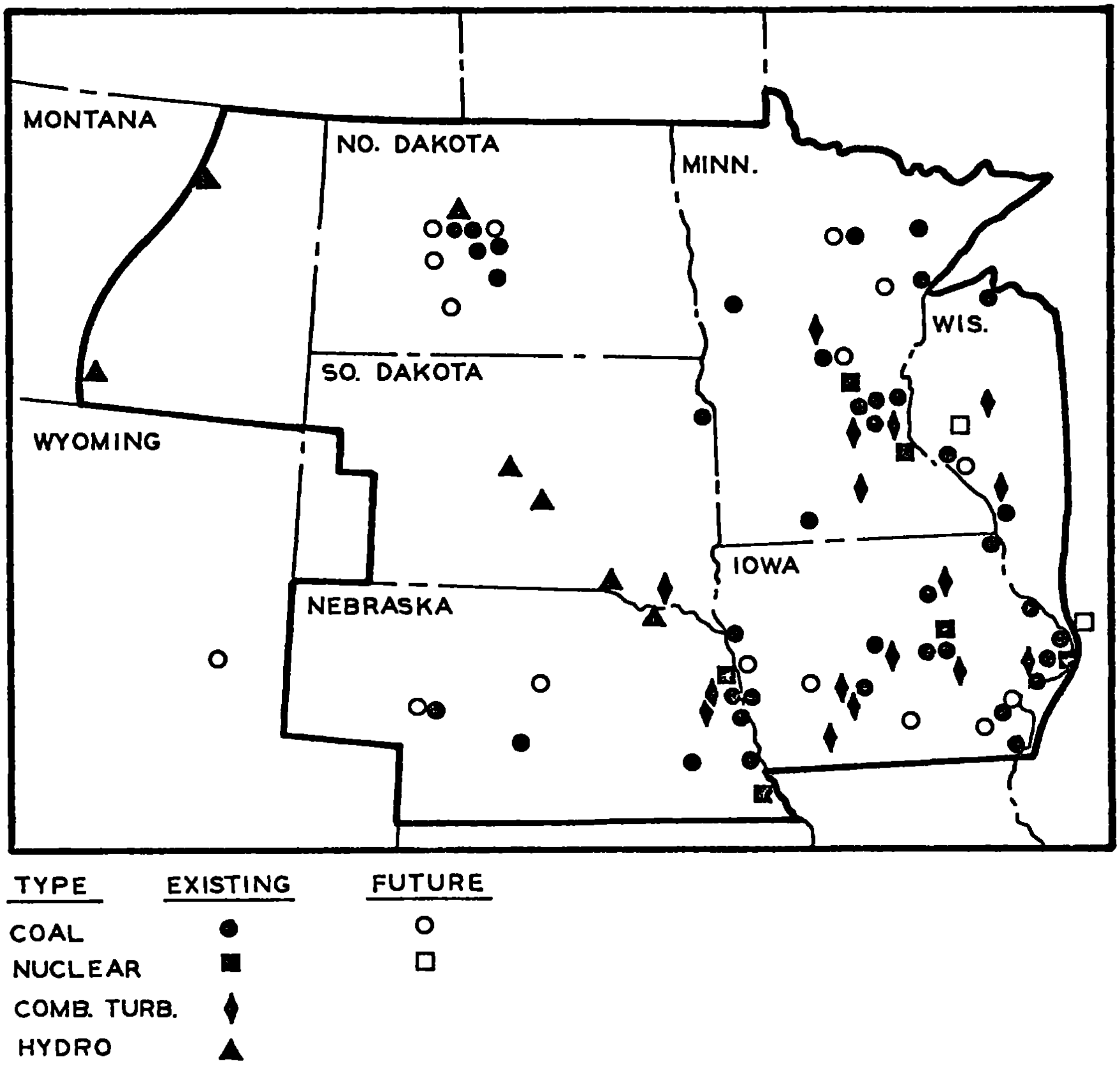


Figure 3-1
MARCA POWER GENERATION BY SOURCE



*SOURCE: MAPP "GENERATION AND TRANSMISSION REPORT 1979-1988"
JUNE 1979

Figure 3-2

EXISTING AND FUTURE GENERATING PLANTS
70 MEGAWATTS OR LARGER

Table 3-6 shows the expected decline, according to utility forecasts, in hydropower generation in comparison to the MARCA total through the 1978-1988 period. Hydropower capability is expected to decline from 2970 MW or 12.2 percent of MARCA total, in summer 1979 to 2790 MW or 8.5 percent in the summer of 1988. The 206 MW reduction occurs entirely within the Dakotas-Montana subarea. These projections are predicted on estimated future water supply and do not reflect less hydroelectric machinery.

Table 3-6
HYDROPOWER GENERATION PROJECTIONS 1978-1988
(MILLIONS OF KILOWATT-HOURS)

	Generation	Percent of MARCA Net Generation
1978 (Actual)	15,495	16.5
1979	13,902	13.2
1980	13,174	11.9
1981	12,922	11.0
1982	12,972	10.2
1983	12,972	10.1
1984	12,974	9.7
1985	12,072	8.6
1986	12,072	8.2
1987	12,072	7.7
1988	12,074	7.5

Type of Energy

The Federal hydropower plants in MARCA except Gavins Point can be operated essentially as peaking or intermediate plants fully integrated with the base loaded thermal plants in the area.

Gavins Point is generally base-loaded to provide steady flows for navigation. The marketing agent purchases off peak energy from thermal resources to meet off peak demands of their customers. The hydropower resources are concentrated on peak to meet firm loads and to replace generation by high cost oil in the MARCA area. Other hydropower plants in the MARCA area are relatively small and essentially are run-of-river providing thermal replacement capacity and energy as river flows make them available.

How it is Used

Two hydropower plants are used as sole providers for local or site specified power within the system in Minnesota. The rest of the plants are on grid. About 35 percent of the total energy is wheeled to certain towns and villages in MARCA.

On Grid

MARCA has more than 13,000 circuit miles of transmission lines rated at 230 KV or higher. The transmission along the western edge of MARCA is sparsely located and generally operates below the 230 KV level. Concentrations of both generation and population centers in eastern Nebraska, Minnesota, and western Wisconsin have resulted in greater transmission concentrations and higher voltage levels in these areas. The large number of coal-fired power plants in North Dakota and the five large Federal hydropower plants located on the Missouri River in North Dakota, South Dakota, and Nebraska have resulted in a concentration of transmission lines adjacent to the Missouri River extending from Gavins Point Dam in Nebraska to Garrison Dam in North Dakota. Table 3-7 shows the distribution of transmission lines in MARCA.

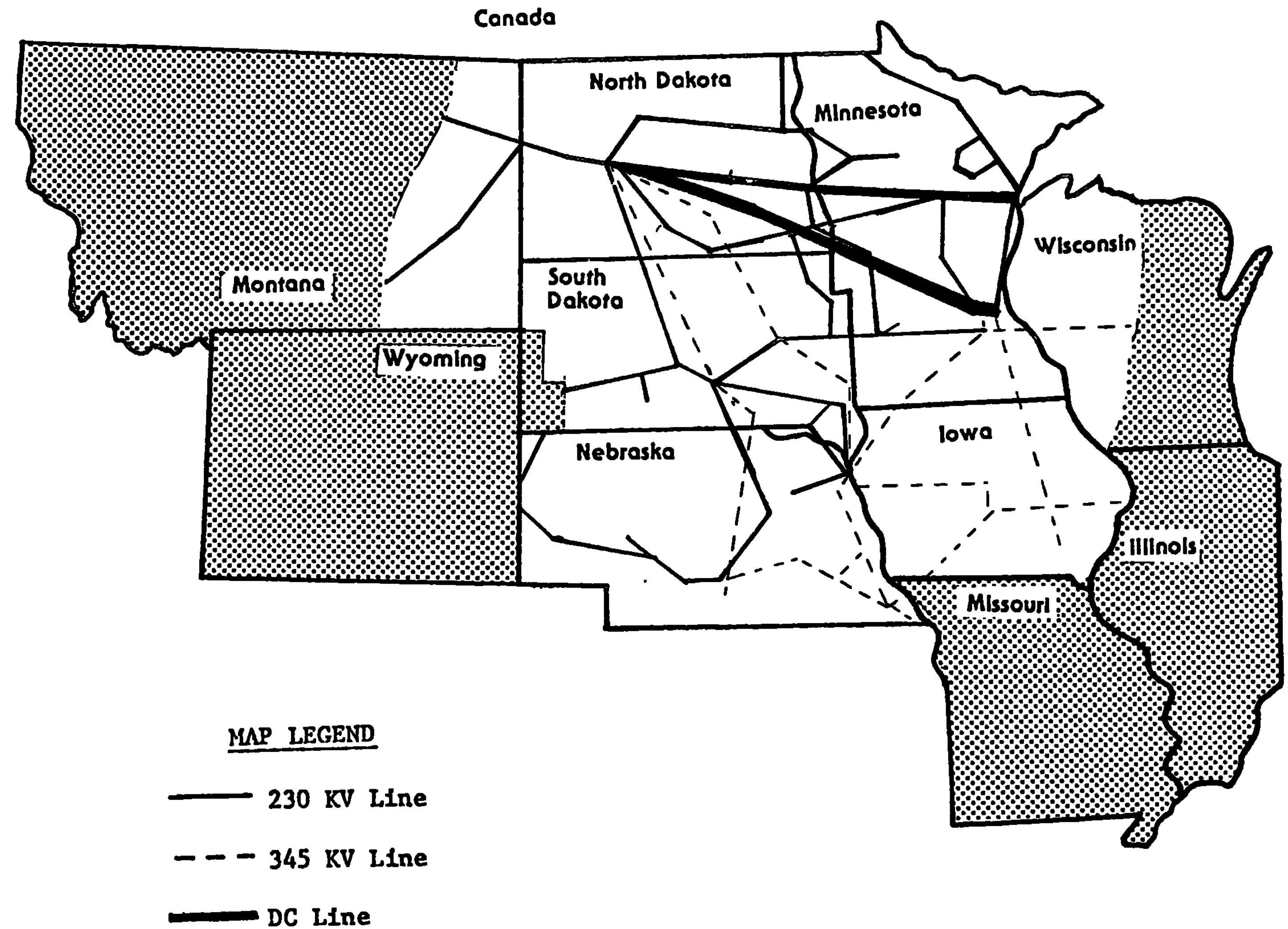
Table 3-7
DISTRIBUTION OF MARCA TRANSMISSION LINES

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

In addition to this transmission network, MARCA and its neighboring Regional Reliability Councils have the capability to transfer power to each other, should it become necessary. Figure 3-3 shows the transmission network for MARCA and figure 3-4 shows the exchange capability between MARCA and the neighboring councils. The reported exchange capabilities represent transfer capabilities above normally scheduled exchanges.

During the 1979-1988 period, significant transmission additions will be made within the region. Approximately 3,000 miles of 345 KV transmission lines will be added and about 230 miles of lower voltage line will be converted to 345 KV. Also planned in the next 10 years is 1,000 miles of 500 KV line which will provide a significant addition to the bulk power transmission between MARCA and Canada.

Figure 3-3
MARCA TRANSMISSION NETWORK



*SOURCE: MAPP "GENERATION AND TRANSMISSION REPORT 1979-1988"
JUNE 1979

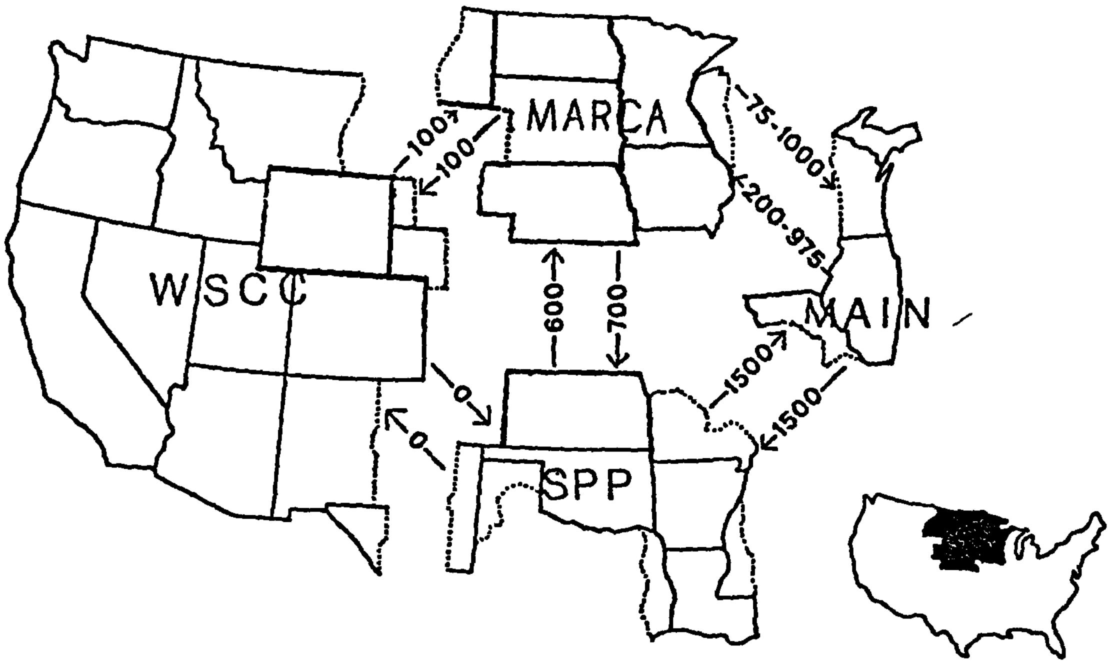


Figure 3-4
MARCA POWER TRANSFER CAPABILITIES (MW)
SUMMER 1977

Ownership

Of the 57 hydropower plants in MARCA, 35 are investor-owned, 10 are owned by public power districts, 8 are Federal, and 1 is owned by a cooperative. Although only 8 are Federal projects, they comprise 85 percent of the hydropower capability in MARCA. Table 3-8 shows existing hydro generating capability for each plant in MARCA.

DOE'S Marketing Agencies

Western Area Power Administration (WAPA), an agency of the Department of Energy, markets all the Federal hydropower in MARCA. WAPA is required by law under the provisions of Section 5 of the Flood Control Act of 1944 (Public Law 534, 78th Congress) to give preference in the sale of power to public bodies and cooperatives; commonly, there is a substantial remainder for sale to private utilities after preference needs have been met. In addition, off-peak power is purchased whenever it is advantageous to conserve hydropower resources for use during peak load periods, thereby reducing oil and gas consumption throughout the marketing area. Rates for sale of power to recover allocated costs are established by WAPA and approved by the Federal Energy Regulatory Commission.

Impacts

Institutional

Institutional constraints for hydropower operation and development relate to permitting and marketing procedures. The slow pace at which permits are issued, legal complications, and the amount of money which manufacturers and investor groups are willing or able to spend, are significant institutional problems. Utilities generally have not been anxious to deal with small power plant producers generally from the standpoint that the power produced at most small hydropower sites hardly justifies the negotiating time involved. A strong market for hydropower can be made by industrial concerns who would develop projects for their own use. In the past, selling power to the utilities has not been the best arrangement since the utility could produce power cheaper at existing fossil fuel or nuclear plants instead of purchasing it from a small hydropower plant. In addition, utilities are allowed to charge hydropower producers a stand-by equipment charge which is needed to provide reliable electrical service to the customer when the customer's hydropower resource is not available. The stand-by charge, by itself, could make a small hydropower development uneconomical to market. Utilities should become a better market under the Public Utilities Regulatory Policies Act (PURPA) since state utilities commissions will re-examine both stand-by rates and the rates utilities must pay for power produced by renewable resources. Another major institutional problem is obtaining the necessary water rights, most notably on existing projects where new power will be added.

Social

Traditionally, development of hydropower has been hindered by relatively large land requirements and relocations as compared to other forms of energy

Table 3-8
EXISTING HYDROPOWER GENERATING CAPABILITY MW
(AS OF JANUARY 1, 1979)

Ownership	Station Name	Location	Summer Capability	Percent of Summer Capability	Winter Capability	Percent of Winter Capability
INVESTOR						
IIGE	MOLINE HYDRO	IL	2.76	.09	2.24	.08
LSDP	BIG FALLS	WI	7.80	.26	7.80	.27
LSDP	HAYWARD HYDRO	WI	0.20	.01	0.20	.01
LSDP	LADYSMITH	WI	1.80	.06	1.80	.06
LSDP	ORIENTA FALLS	WI	0.80	.03	0.80	.03
LSDP	SUPERIOR FALLS	WI	1.90	.06	1.90	.06
LSDP	SAXON FALLS	WI	1.50	.05	1.50	.05
LSDP	THORNAPPLE	WI	1.40	.05	1.40	.05
LSDP	WHITE RIVER	WI	1.00	.03	1.00	.03
MPL	BLANCHARD	MN	11.80	.40	11.80	.40
MPL	FOND DU LAC	MN	11.80	.40	11.80	.40
MPL	KNIFE FALLS	MN	1.90	.06	1.90	.06
MPL	LITTLE FALLS	MN	3.30	.11	3.30	.11
MPL	SYLVAN	MN	1.90	.06	1.30	.06
MPL	THOMSON	MN	70.00	2.36	70.00	2.40
MPL	WINTON	MN	4.00	.13	4.00	.14
MPL	PILLAGER	MN	1.80	.06	1.30	.04
MPL	SCANLON	MN	1.40	.05	1.40	.05
NSP	APPLE RIVER	WI	3.20	.11	3.20	.10
NSP	CHIPPEWA FALLS	WI	22.00	.74	22.00	.75

Table 3-8 (cont'd)
EXISTING HYDROPOWER GENERATING CAPABILITY MW
(AS OF JANUARY 1, 1979)

Ownership	Station Name	Location	Summer Capability	Percent of Summer Capability	Winter Capability	Percent of Winter Capability
INVESTOR						
NSP	CORNELL	WI	30.90	1.04	30.90	1.05
NSP	DELLS	WI	8.40	.28	8.40	.29
NSP	HOLCOMBE	WI	33.30	1.12	33.30	1.14
NSP	HENNEPIN ISLAND	MN	12.00	.41	12.00	.41
NSP	HATFIELD	WI	2.70	.09	5.40	.19
NSP	JIM FALLS	WI	11.40	.39	11.40	.38
NSP	LOWER DAM	MN	7.30	.25	8.30	.29
NSP	MENOMONIE	WI	5.50	.19	5.50	.18
NSP	RIVERDALE	WI	0.50	.02	0.50	.02
NSP	ST CROIX FALLS	WI	22.00	.74	22.00	.75
NSP	TREGO	WI	1.20	.04	1.20	.04
NSP	WISSOTA	WI	36.40	1.23	36.40	1.25
OTP	BEMIDJI HYDRO	MN	0.74	.02	0.74	.03
OTP	DAYTON HOLLOW	MN	0.98	.03	0.98	.03
OTP	HOOT LAKE HYDRO	MN	0.86	.03	0.86	.03
OTP	TAPLIN GORGE	MN	0.56	.02	0.56	.02
OTP	WRIGHT	MN	0.51	.02	0.51	.02
OTP	PISGAH	MN	.62	.02	.62	.02
TOTAL INVESTOR (38)			328.13	11.04	330.21	11.29

Table 3-8 (cont'd)

EXISTING HYDROPOWER GENERATING CAPABILITY MW

(AS OF JANUARY 1, 1979)

Ownership	Station Name	Location	Summer Capability	Percent of Summer Capability	Winter Capability	Percent of Winter Capability
PUBLIC POWER DISTRICTS						
NPPD	BLUE SPRINGS	NE	0.35	.01	0.35	.01
NPPD	L. BABCOCK	NE	40.00	1.35	40.00	1.37
NPPD	JEFFREY	NE	18.00	.61	18.00	.62
NPPD	JOHNSON I	NE	19.00	.64	19.00	.65
NPPD	JOHNSON II	NE	19.00	.64	19.00	.65
NPPD	KEARNEY	NE	1.00	.03	0.00	.00
NPPD	MINNECHADUZA	NE	0.22	.01	0.22	.01
NPPD	NIOBRARA	NE	0.25	.01	0.25	.01
NPPD	MALONEY	NE	24.00	.81	24.00	.82
NPPD	SPENCER 1/	NE	1.80	.06	1.80	.06
TOTAL PUBLIC POWER DISTRICTS (10)			123.62	4.17	122.62	4.20
FEDERAL						
COE	BIG BEND	SD	471.00	15.86	525.00	12.95
WPRS	CANYON FERRY	MT	57.99	1.95	57.99	1.94
COE	FT. PECK	MT	216.00	7.27	211.00	7.21
COE	FT. RANDALL	SD	347.00	11.68	310.00	10.61
COE	GARRISON	ND	486.00	16.36	463.00	15.83
COE	GAVINS POINT	SD	92.00	3.10	69.00	2.36
COE	OAHE	SD	684.00	23.03	683.00	23.35
WPRS	YELLOWTAIL	MT	143.50	4.83	137.50	4.71
TOTAL FEDERAL (8)			2497.49	84.08	2456.49	83.96

1/ Also known as Northern

Table 3-8 (cont'd)
EXISTING HYDROPOWER GENERATING CAPABILITY MW
(AS OF JANUARY 1, 1979)

Ownership	Station Name	Location	Summer Capability	Percent of Summer Capability	Winter Capability	Percent of Winter Capability
COOPERATIVE						
DPC	FLAMBEAU	WI	21.00	.71	16.00	.55
TOTAL COOPERATIVE (1)			21.00	.71	16.00	.55
TOTAL INVESTOR (38)			328.13	11.04	330.21	11.29
TOTAL PUBLIC POWER DISTRICT (10)			123.62	4.17	122.62	4.20
TOTAL FEDERAL (8)			2497.49	84.08	2456.49	83.96
TOTAL MARCA (57)			2970.24	100.00	2925.32	100.00

SOURCE: MARCA Regional Reliability Council Coordinated Bulk Power Supply Program
April 1, 1979

generation. However, in the MARCA area, as in other areas in the United States, most non-Federal hydropower sites were developed early in time before large-scale commercial, industrial, residential, and transportation development. Therefore, the existing non-Federal developments have not caused any serious disruption in social harmony due to massive relocations of transportation facilities, residences, and commercial buildings. The existing Federal hydropower projects have required larger commitments of land and human resources than the smaller, local hydropower projects but they also operate on a multiple-purpose basis, thus not only do they provide power but flood control, navigation, water supply, and recreation services. Most of the Federally owned reservoirs in MARCA operate on a set of guidelines developed over many years whereby the desires and expectations of persons or groups residing near or adjacent to the projects are taken into consideration. Continuing problem areas are under investigation by the Corps of Engineers and the Water and Power Resource Service in order to improve the social-environmental aspects of the projects. Problem areas on the Missouri River which are reservoir related are the subject of on-going studies and programs seeking resolution of upstream waterlogging, bank erosion, bed degradation, and fish and wildlife mitigation.

Economic

The procedures determining economic justification of non-Federally financed hydropower projects differ from the procedures used in Federal projects. The economic analysis of a potential non-Federal development may be used on a period of 100 years or the estimated service life of the project, whichever is shorter. Economic justification of Federal projects compares estimates of total project benefits with estimates of total project costs. The project is considered economically justified when the benefit to cost ratio is equal or greater than unity; when there is no more economical means of accomplishing the same purpose; and when each separable segment or purpose provides benefits at least equal to its cost. The benefits are equivalent to the cost of power from the most likely alternative source. Traditionally, the cost of the assumed alternative was based on the type of financing expected to apply to the alternative plant including taxes and insurance. Under the new Principles and Standards for water resource planning, Federal financing without taxes and insurance is the general standard for estimating the alternative costs.

Financial feasibility of a power installation is another analysis which must be completed for Federal projects. It is determined by comparing the estimated annual power revenues from a project with the estimated annual costs of power produced. If annual revenues expected from power sales are sufficient to repay annual power costs over 50 years, the power portion of the project is considered financially feasible.

Hydropower installations with high capital and low operating costs can compare favorably at times or be competitive with alternative fuel-dependent sources which have high operating and low installation costs. Hydropower will become more favorable as the price of oil increases. Older thermal plants which have relatively higher operation costs are generally not used during base and intermediate load conditions but only during peak load requirements.

Within the MARCA area, rivers and streams which can produce base load energy are relatively scarce. Only the large, existing Corps of Engineers reservoirs on the Missouri River with ample storage could provide a relatively steady operation on a seasonal basis. Historically, much of the need has been for base load generation where high capital costs and low operating costs combine to produce power at a low unit cost. Cheap fuels with high efficiency have been used to keep operating costs to a minimum. Gas or oil-fired combustion turbines have been used effectively for peaking, since only a small amount of energy is involved compared to the base load operation, and the high fuel cost is counterbalance by very low capital cost. As a substitute capacity, hydropower is able to replace thermal generation to the extent its water supply will support. This means that a plant that has a small amount of water to be used to serve peak loads for a few hours per day, replaces gas or oil-fired turbines. On the other hand, any base load plant with large amounts of energy can be evaluated against a nuclear plant. More hydropower is being examined for use as peaking plants, especially as the cost of oil escalates and provides increased economic benefits. But in the MARCA area where many water supplies are limited, the plant factor of a hydropower plant may not be as great as needed to replace alternative sources given the characteristics of the system within which it operates. If the hydropower project adds only capacity to an already existing hydropower facility, but results in a change in total project operation, the value of the added capacity is measured by both the capacity value and the net effect on "system" operations that results from the new generating regime.

The value of hydropower for future use is appealing from the standpoint of:

- it uses a renewable energy resource
- it is a proven reliable technology
- it has a wide range of operating flexibility
- it is an inflation hedge

Although hydropower is very capital intensive, the cost of power from the plant is resistant to inflationary pressures as compared to thermal plants which are heavily dependent on fuel. Some of the basic problems associated with hydropower development may indicate to some extent the reasons why hydropower has not been more fully developed:

- limited energy production
- large land requirements
- water and use conflicts

- large capital requirements
- environmental disruptions
- long lead time to construction

Physical

Environmental

Existing hydropower plants are subject to certain impositions due to environmental constraints. In most cases these operating constraints are agreed to between the plant owner-operator and the respective State officials. Modification of either operating criteria or discharge facilities is sometimes required to avoid adverse impacts on water quality and fish downstream of the projects. Some hydropower sites have minimum flow requirements to prevent adverse effects during both release periods and off-peak periods. Others require closing of gates, prohibiting fish movement, and, in some cases, special provisions must be made to prevent fish from being drawn into the turbine. Temperature can be a problem in hydropower installations where water released originates from deep in the reservoir and is below the existing minimum temperature limits. Turbidity levels of releases often exceed water quality standards; however, the turbidity levels have not generally caused any problems downstream and they may be beneficial to planktivorous fishes. Fluctuating reservoirs have some adverse effects on fish spawning areas along the shoreline. However, the larger reservoirs are operated to meet target pool levels during spawning periods to enhance spawning. This involves raising the reservoir to inundate shoreline vegetation in the spring and regulating at or above these levels through the spawning season. In the case of the large Federal projects on the Missouri, this has been accomplished with little disruption of existing purposes.

Manipulation of pool levels for fish spawning enhancement at the large reservoirs generally is designed to complement the runoff conditions and must be very carefully scheduled based on the actual conditions that occur. Generally conditions are favorable to enhance fish spawning at one or more reservoirs each year.

Hydrologic

Releases from the major Federal projects on the Missouri River, which constitute the bulk hydro power capacity in MARCA, are rarely made for power alone; flood control, water supply, navigation, recreation, and fish and wildlife receive on-going considerations. Full gate discharge through the power plants range from 15,000 cfs at Fort Peck to 103,000 cfs at Big Bend. Over the years, less than 2 percent of project releases have been spills or flows which by-passed the power turbines because of insufficient capacity.

Drouth period rule curves for the main stem system are designed to deplete the 40 million acre-feet of multiple-use storage during a repetition of the most critical period of record - the 12-year sequence from 1930 through 1941.

One characteristic of these curves is curtailment of downstream releases as upstream depletions grow; the result is a quite uniform draft on storage regardless of the depletion level. Since the drouth of the '30's has a recurrence interval many times the life of the main stem projects, its full impact is considered too severe a test by which to determine dependable capacity. To reflect adverse conditions, it is considered reasonable to select the generation that might be expected at the end of the drought of the 50's and early 60's, i.e., 1961, which is the second worst drought of record.

Operation of the main stem reservoirs is geared to providing releases commensurate with the depletion level throughout the drought of record. Consequently, reservoir levels - and hence, capability - for a given water year would be essentially the same over a wide range of depletions.

The effect of future depletions on main stem hydropower generation may be summarized as follows: peaking capability in kilowatts will be reduced by less than 10 percent; energy generation will decline about 500 KWH for every acre foot withdrawn.

Chapter 4
DEMAND SUMMARY

4.1 CAPACITY AND ENERGY DEMANDS

To provide a range of electric power demand forecasts, three projections were developed from published and readily available information and data. The three projections are intended to define a reasonable range of future demands from both high and low projections which reflect varying assumptions. A "median" projection was selected as representative of future power and energy demand for the MARCA region. The future projections were developed by Harza Engineering Company and are presented in the report "Phase II - Future Electric Power Demand and Supply" which is an Appendix to the National report prepared by the Institute for Water Resources. Projection I is based on MARCA's projections, whereas Projection II is based on a low forecast made by the Institute for Energy Analysis, Oak Ridge Associated Universities, September 1976. The Projection II forecast considers the impact of various conservation and load management policies and other energy sources such as solar, geothermal, cogeneration, and wind systems along with a lower population growth rate. Projection III is based on the "Consensus Forecast of United States Electricity Demand" which represents an average of 15 energy demand forecasts from Federal and private economists between September 1973 and April 1975. The forecast assumes that a determined national effort to reduce demand for energy through application of energy-saving technologies will be successful and that continued high world oil prices will keep domestic energy prices high, resulting in lower demand. The "median" projection is the median value of the three projections, Projections I, II, and III. When the median forecast is used as a base, the corresponding high and low forecasts establish reasonable limits within which new hydropower capacity and energy can be analyzed. The projection methodology recognizes the impact of fuel prices and the expected increased usage of major appliances involved in space heating, water heating, cooking, clothes drying, air conditioning, refrigerating and lighting. Table 4-1 summarizes the electricity distribution in each major end use category for an area representative of MARCA for the base year 1970. Energy sources for these appliances include utility gas, electricity, fuel oil, bottled gas, coal, and other. The total primary and electrical energy is measured at the point of use.

ENERGY DEMAND

Based on the "median" projection, annual electric energy in MARCA is expected to grow from 92,500 GWH in 1978 to 130,300 GWH in 1985, resulting in an average annual growth rate of 5.0 percent. Beyond 1985, the growth of total energy consumption is expected to slow. The "median" projection indicates that total electric energy demand will have an average annual growth rate of about 4.5 percent between 1985 and 1990, and drop to 3.7 percent between 1990 and 2000. In the year 2000, the "median" electric energy demand is expected to be 233,000 GWH.

Table 4-1
ENERGY CONSUMPTION, PERCENT DISTRIBUTION OF TOTAL AND ELECTRICAL ENERGY

End Use	Total Energy Percent	Electric (Percent of Total)
Space Heating	70.7	1.4
Water Heating	12.2	15.6
Cooking	3.8	23.7
Clothes Drying	1.0	61.0
Air Conditioning	1.5	100.0
Refrigeration	3.0	100.0
Lighting	2.0	100.0
Other	5.8	24.2
TOTAL	100.0	12.3

PEAK DEMAND

Presently, MARCA is a summer peaking system, and is expected to remain so in the future. In 1978, the summer peak was about 18,000 MW. The peak is expected to grow to 26,200 MW in 1985, at an average annual growth rate of 5.5 percent. In the year 2000, the "median" peak demand is expected to be 46,500 MW, representing an average annual growth rate of 4.4 percent for the period 1978-2000.

LOAD FACTOR

In 1978 MARCA had an annual load factor of 58.7 percent. Within MARCA, utilities have annual factors varying between 50 and 66 percent. From the projected peak and energy demands forecast by the utilities, future annual load factors are expected to average 57 percent.

Table 4-2 shows the projections of per capita consumption, total energy demand, and peak demand for the years 1985, 1990, 1995, and 2000.

Table 4-2
ELECTRICAL POWER DEMAND

	1978	1985	1990	1995	2000
PROJECTION I					
Per Capita Consumption (MWH)	9.0	12.7	15.6	19.0	23.0
Total Demand (Thousand GWH)	92.5	134.9	170.9	211.5	261.1
Peak Demand (GW)	18.0	27.1	34.1	42.2	52.1
PROJECTION II					
Per Capita Consumption (MWH)	9.0	10.8	12.2	13.9	15.8
Total Demand (Thousand GWH)	92.5	114.6	133.6	155.0	179.8
Peak Demand (GW)	18.0	23.0	26.7	30.9	35.9
PROJECTION III					
Per Capita Consumption (MWH)	9.0	12.2	14.9	17.5	20.5
Total Demand (Thousand GWH)	92.5	130.3	162.6	195.1	233.0
Peak Demand (GW)	18.0	26.2	32.4	38.9	46.5
MEDIAN PROJECTION					
Per Capita Consumption (MWH)	9.0	12.2	14.9	17.5	20.5
Total Demand (Thousand GWH)	92.5	130.3	162.6	195.0	233.0
Peak Demand (GW)	18.0	26.2	32.4	38.9	46.5
Reserve Margin (Percent)1/	21.9	17.0	17.0	17.0	17.0
Resources to Serve Demand (GW)2/	21.9	30.6	37.9	45.5	54.4
Load Factor (Percent)	58.7	56.8	57.2	57.2	57.2

1/ Reserve capacity needed as standby for the system.

2/ Ability to meet peak demand and margin.

Chapter 5
METHODOLOGY

5.1 REGIONAL PROCEDURES AND CRITERIA

Regional Screening Criteria and Procedures

Identification of a hydropower system for the MARCA region involved all of the activities and tasks required to identify and assess the potential for developing hydropower facilities at existing dams and potential sites. The result of this was the formulation of regional hydropower plans for MARCA. The system evaluation was accomplished in four separate stages with the first three stages used to screen sites which did not meet increasingly severe evaluation criteria. The fourth stage encompassed the identification of regional plans. Site identification was accomplished within hydrologic boundaries; each Corps of Engineers Division had responsibility for selecting standards, initial screening criteria, and reviewing studies performed by the Districts for projects in their river basin areas. The screening process in MARCA was completed by 4 district offices; 2 from the Missouri River Division, Omaha and Kansas City and 2 from the North Central Division, St. Paul and Rock Island.

The Hydrologic Engineering Center in Davis, California, provided technical support by conducting training sessions and providing computer screening processes. The Missouri River Division reviewed the results of the screening studies, performed by each District, for consistency and accuracy.

Stage 1

The initial phase of the study began in April 1978 when a preliminary inventory of existing and potential damsites was assembled. Existing dams were identified using the National Inventory of Dams publication and potential sites were located by referencing past studies and reports by the Corps of Engineers, the Water and Power Resources Service, the Soil Conservation Service, the Federal Energy Regulatory Commission, and other Federal and non-Federal sources. Nationally, over 50,000 existing and 20,000 potential sites were identified, of which about 815 were in the MARCA area.

Sites which did not possess either sufficient storage, head, or flow to generate a minimum amount of hydropower were screened. Sites which could not generate one megawatt utilizing a discharge equal to the project storage in a 24-hour period at maximum head were screened out. The following criterion were used:

$$P = \frac{Qhe}{11.8} = .072Qh$$

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

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

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

Where: S = Storage in Acre-Feet (A-F)

The results insured that any reasonable site would not be screened from the active inventory. Stage one was completed in late 1978 and about 249 sites in MARCA were retained for evaluation in Stage 2.

Stage 2

During Stage 2 which began about February 1979, a second screening was performed in order to identify those sites which showed some possibility of being economically feasible. In order to evaluate site hydrology, costs, and benefits for the large number of sites, computer routines were developed. These routines analyzed streamflow data using flow-duration and sequential flow techniques to develop a range of capacity and energy potentials. The computer also utilized generalized cost curves and regional power values for energy and capacity to determine the economic feasibility of the project. The size of the project was selected as that size where net benefits are maximized.

The screening was accomplished by eliminating those sites which showed an installed capacity of less than 1 MW or a ratio of benefits to costs of less than one. About 180 MARCA sites were retained after this evaluation.

Stage 3

During Stage 3, sites were evaluated using economic, social, environmental, and public acceptability criteria in an iterative process. Two separate screenings were made; the first screening based on economic feasibility and the second based on the other criteria mentioned above. With Stage 3 collection activities beginning about June 1979, more detailed information relative to head, flows, reservoir storage, tailwater, dam configuration, and location were developed. The objective of the activity was to provide a more refined analysis of power-related costs and benefits using computer routines. To pass the first screening during Stage 3, sites were required to have at least one megawatt of installed capacity and a minimum benefit-cost ratio for developed and single-purpose undeveloped sites of 1.0 and 0.70, respectively. The first screening began about January 1980 and the second screening started in February 1980, ending in April of 1980. About 77 sites remained after the first screening under Stage 3 including 29 existing hydropower plants which showed no feasible additions, 30 existing hydropower plants which showed feasible additions, 2 undeveloped sites with feasible additions, and 16 existing damsites which currently have no power installation, but showed a potential for feasible power additions.

The environmental, social, and public acceptability criteria considered overriding adverse impacts such as designated Wild and Scenic River reaches, endangered species, wetlands, impacts to fishery habitat, water quality, cultural resources sites, and park lands. Both reservoir and downstream flow conditions were considered. Known opposition to previously considered undeveloped sites was considered, as well as possible significant economic impacts stemming from relocation of roads, bridges, railroads, and towns which were not adequately reflected in the cost curves.

The State of Montana provided assistance in the evaluation of Missouri River Division sites within that State. Nine unacceptable sites identified by the Omaha District were confirmed by the State and two others were ruled out on environmental grounds as a result of the State's recommendation. All of these sites are located in the WSCC portion of Montana, thus, they are not part of this report. About 77 sites remained for Stage 4 evaluation. Of these, 2 are undeveloped with feasible additions; 29 are existing hydro plants with no feasible additions; 30 are existing hydro plants having feasible additions; and 16 are existing damsites currently not producing power with feasible power additions.

Stage 4

The principal tasks involved in this activity centered on the formulation of alternative plans for hydropower development. Major tasks included: An analysis and ranking of potential sites according to economic, environmental, social and institutional criteria; formulation of hydropower systems to help meet projected regional power demands and evaluation of impacts and accomplishments of each system.

The sites were ranked on the basis of net benefits, highest to lowest. The results of the economic ranking were then compared with a measure of the environmental, social, and acceptability results to arrive at an overall ranking. However, in the MARCA area, all economic rankings were used as a final measure of the consolidated site ranking since sites with overriding environmental, social, and acceptability impacts were eliminated from further consideration. In some cases net benefits for projects with competing water uses were determined by reducing the net power benefits to account for the use of water for existing water supply functions.

Data Collection Procedures

The initial phase of the National Hydroelectric Power Study consisted of data collection to develop a comprehensive preliminary inventory (Form 1) of hydropower potential. The data included the basic location and pertinent data of all existing and undeveloped sites. Data sources for existing and undeveloped sites were: the National Inventory of Dams; reconnaissance, survey and other reports of the Water and Power Resources Service, the Soil Conservation Service, the Corps of Engineers, the Federal Energy Regulatory Commission, and the Geological Survey. Additional data from State agencies and public and private power utilities were reviewed.

Initial tasks in gathering pertinent data for each existing and undeveloped site included: determining drainage area controlled by the site; selecting representative USGS gaging station for each site; listing of energy and installed capacity if available; and location in terms of state, county, stream, longitude and latitude.

When controlled drainage area information was not available, the data were planimetered from available topographic maps. Representative gaging stations for each site were determine by either map reconnaissance or by a Hydrologic Engineering Center (HEC) computer program which analyzed the drainage area controlled by the site, the drainage area of adjacent gages, and their period of record. Pertinent data on storage and height of dam were available from the National Inventory of Dams report. On sites where these were not available, data were retrieved from existing reports and from personal contacts with owners. For undeveloped sites data were received from the appropriate planning agency, sometimes supplemented by map reconnaissance.

Additional data were required for the sites that passed the Stage I screening. These consisted of more detailed information on the reservoir for determining the height of the potential power pool and its volume in acre-feet and surface area in acres. Additional information gathered on the dam included length of the embankment and height of flood control and conservation pools. Rating curves were also developed for the outlet tailwaters. These basic pertinent data for the dam and reservoir, when not available from existing reports, were determined from topographic (7-1/2 minute U.S.G.S. quad) maps. Unless tailwater rating curves were available at an existing dam, a series of prototype tailwater rating curves was developed for dams with drainage areas up to 1,000 square miles. For dams controlling over 1,000 square miles, rating curves from gaging stations where upstream drainages had similar topography and areas were used. Successively more detailed information on physical characteristics was collected on certain projects during the study in order to refine computer inputs and to provide less uncertainty on results.

Periodic contacts from utility officials and State and Federal agencies provided information on current activities and studies relating to potential hydropower development at specific sites. Results of studies relative to adding hydropower to existing damsites by utilities were received late in the Corps' study process. As public information regarding the studies was disseminated, more specific information on certain sites and studies was volunteered by agencies and utilities.

The environmental, social, and public acceptability aspects of the study were examined during the second screening of Stage 3. Known data available from on-going or past basin studies within each District were utilized as an initial source of environmental and social values. This source was supplemented by additional data provided by State agencies. Extensive site specific environmental studies were not carried out in this study. Further study of any one site may provide further information on environmental acceptability. Letters received from local groups and persons expressing comments on specific sites served as a source of background information relative to social and acceptability issues. Likewise, letters and phone calls received from other sources such as private and public utilities served as a means of supplementing the collected data.

Environmental information which could be attained without additional study included data on:

Acres of National/State Park lands impacted

Miles of National/State Wild and Scenic Rivers affected

Miles of Potential Wild and Scenic Rivers affected

Acres of Estuary and Wetland areas affected

Cultural Resource Sites impacted

Critical Wildlife Habitat areas affected

Miles of Fishery Habitat impacted

Endangered species impacted

Water Quality affects

Others

Information on social impacts related to:

Number of persons relocated

Number of towns relocated

Number of businesses relocated

Miles of Highways and railroads relocated

Number of bridges relocated

Miles of Navigation impacted

Acres of farmland inundated

Public Acceptability issues centered on:

Political factors, support or opposition

Federal and State agency support or opposition

Local public support or opposition

Environmental support or opposition

Other social group opposition or support

Utility Interest group support or opposition

In many cases, full documentation of the parameters was impossible. However, sufficient information was obtained on critical factors which provided the basis for inclusion or exclusion of specific sites from the active file.

5.2 REGIONAL DEMAND ASSESSMENT

As stated in Chapter 4, the median projection of annual electric energy in MARCA is expected to grow from 92,500 GWH in 1978 to 130,000 GWH in 1985. In the year 2000, the demand is expected to be 233,000 GWH. The peak demand is projected to increase from 18,000 MW in 1978 to 46,500 MW in 2000. The peak demand represents an overall compound growth rate for the 22-year period of 4.4 percent, annually. The per capita consumption for MARCA is expected to increase by 11.5 megawatt-hours between 1978 and the year 2000, however, the annual rate of growth is expected to decrease from a present 4.5 percent to 3.8 percent for the 22-year period. Assuming a capability margin of 17 percent throughout the period, the required resources to meet the expected demand, in gigawatts, are 30.6, 38.0, 45.6, and 54.4 for the years 1985, 1990, 1995, and 2000, respectively. If all the incremental capacity carried through Stage 4 were developed and combined with the existing capacity, hydropower could provide between 13 and 7 percent of the required resources to meet the demand, depending on the projected year of demand. It should be noted that with the increasing cost of energy supplies, the projected energy and capacity demands appear to be decreasing. Therefore, the actual growth rate may be less than projected and the additional hydropower capacity and energy may meet a higher percentage of the total, thus, saving more fuel.

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 with 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
- 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. In addition, at the request of the Western Environmental Trade Association, the study coordinator discussed the screening of sites for the MARCA area as well as those in Montana at their annual meeting on 6 March 1980 at Bozeman, Montana. Two public meetings; a Montana coordination meeting; and a Montana public meeting were held to discuss the status and results of the study.

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 the MARCA region. Of the 104 people in attendance, nine verbal statements were presented and three agencies submitted written statements. The following paragraphs recapitulate positions expressed during the meetings.

> 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. Concern was also expressed on the delay of the two potential hydroelectric project proposals; Gregory County Pumped Storage and Libby Dam Additional Units and Reregulating Dam.

A representative of the Big Horn Conservation District and the chairman of the Crow Tribe Water Resources Commission expressed a desire for the addition of multi-purpose dams including hydropower facilities on the Little Big Horn River. They said sites located in this area would help ease the energy needs of power deficient northeastern Wyoming and southeastern Montana, and also reduce the serious flooding problems along the Little Big Horn River. (Subsequent studies were run on the site using data provided by local interests , it was found infeasible for development of hydropower.)

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.

In a written statement, the North Dakota Legislative Council suggested the study should consider not only hydropower needs but also the transportation needs of the upper midwest.

Representatives from Western Area Power Administration and the Midwest Electric Consumers Association expressed support of additional hydropower development on the Missouri River, notably - potential additions to the existing Fort Peck, Montana and Garrison, North Dakota projects and the construction of the potential Gregory County Pumped Storage Project, South Dakota, proposed by the Corps of Engineers.

A member of the Yankton Sioux Tribe stated that in small hydropower studies the requirement that the development of small-scale hydropower be at existing projects acts as a constraint that is precluding the development of many feasible sites on reservations.

The Director of Community Development for the City of Granite Falls outlined current proposals for future energy development for the State of Minnesota.

Coordination Meeting

On 27 March 1980, a National Hydropower Coordination meeting was held in Helena, Montana, at the request of the Governor. Representatives from the Corps of Engineers (Missouri River Division and North Pacific Division), the Montana Department of Natural Resources Council, Montana Department of Fish, Wildlife and Parks, U. S. Geological Survey, Lt. Governor's office, Water

Quality Bureau and the Environmental Quality Commission were in attendance. The purpose of the meeting was to provide a mechanism through which State agencies could provide input to the studies and to review and provide comments on available study results. The meeting resulted in the Corps of Engineers providing the State with a listing of all the active sites in Montana. (As a result of this meeting, 11 Montana undeveloped sites were viewed by the State as unacceptable on environmental, social, and public acceptability grounds and the sites were placed in the inactive file.)

Public Meeting August 1980

On 11 August 1980, a public meeting was held in Omaha, Nebraska, to present the results of the study relating to MARCA and to seek public comments and concerns regarding those results. Of the 33 people in attendance, three verbal statements were presented, and four agencies submitted written statements. The following paragraphs summarize positions expressed during the meeting.

A representative of Basin Electric Power Cooperative stated the Cooperative fully endorses the development of hydroelectric power, but feels the Federal Government is not expediting the development of the potential Gregory County Pumped Storage project in South Dakota. He stated that if hydroelectric peaking facilities are not provided by the Federal Government, Basin Electric would be forced to build their own facilities which would be more costly to both the environment and the consumer.

The Assistant Executive Director of the Mid-West Electric Consumers Association expressed concern that the study does not include institutional benefits, social goals, or the institutional factors associated with the development of hydropower facilities. However, the Corps was commended on the overall study progress. The Association endorses the development of additional hydropower at Fort Peck, Garrison, and Libby dams and the development of the potential Gregory County Pumped Storage project. They also urged the Corps to move forward on the construction of additional facilities at several projects in Montana and Wyoming.

The Executive Director of the Missouri Basin Systems Group supported the statements and concerns expressed by Basin Electric Power and Mid-West Electric Consumers Association.

In a written statement, the Central Power Electric Cooperative, Inc., expressed their support of additions to Fort Peck and Garrison dams and the development of the potential Gregory County Pumped Storage project. They also requested that the power generated from the projects be allocated to preference customers within the region.

The Water and Power Resources Service, in a written statement, informed the Corps that they have ongoing studies on the Norden, Calamus, and Merritt projects in Nebraska. They summarized their preliminary findings for those projects.

In a written statement, the Mayor of the City of Thief River Falls, Minnesota, stated that the city owns an existing hydropower site and presented data for the project.

Lake Superior District Power Company, in a written statement stating past studies on a hydropower project they own, indicated that additional capacity is not justified. They suggested further studies should be analyzed on an individual site basis in order to incorporate the proper river flow conditions.

Draft Report Review Comments

As a result of review by Federal, State, and other interested agencies of the draft regional report, the following paragraphs present summary statements of written comments from respective agencies.

Water and Power Resources Service, Billings, Montana, requested the Bighorn Site (ID No. MTIMR0123) be deleted as a potential hydropower site due to (1) extensive costs for powerhouse facilities; (2) existing downstream flow constraints; and (3) the location within the Crow Indian Reservation. A 10MW addition at the Yellowtail Afterbay Dam was noted as appropriate for inclusion in the study. (The 303.6MW unit considered in the study was deleted as requested and the afterbay potential added in its place.)

South Dakota State Planning Bureau - an editorial comment.

Federal Energy Regulatory Commission, Chicago, stated the concept of diminishing returns should be given to size the installation, and noted capacity to be added at existing units appeared oversized in some cases. (Several editorial comments were incorporated in the report.)

North Dakota State Water Commission, Bismarck, stated recognition should be given to the value of the natural resources at Lake Sakakawea and expressed concern over greater fluctuations in the Missouri River as a result of potential power additions. The Commission noted power allocations from Garrison Dam have favored Minnesota while North Dakota was expected to contribute to the upper midwest with diminishing benefits. The Commission indicated it could give no support to additional units at Garrison Dam until studies show there will be no adverse effects on the downstream area.

The Fish and Wildlife Service stated the studies centered on economic feasibility with basic environmental screening and after further study some sites may prove to be environmentally unacceptable. The Service stated they could not concur that all sites in Stage 4 were environmentally acceptable since the environmental screening was considered by them to be basic. Several editorial comments were also provided. (The editorial comments were incorporated in the report.)

Environmental Protection Agency, Region V, indicated that it would be useful to know how many hydropower plants, which were eliminated due to marginal economics, may become cost effective as energy costs increase. The Agency noted environmental impacts will be site dependent; the regional report should not be the basis for the determination of significant impacts; and the agency should be contacted as plans progress to implement any of the projects. They further noted the median energy growth rate between now and 1985 of 5 percent appeared conservative based on recent trends and that there is a moratorium on nuclear plant construction in Wisconsin. (Projections noted this change.)

North Dakota Parks and Recreation Department opposes the Garrison Dam additional units if a reregulation dam were to be constructed or if the rise and fall of the Missouri River and reservoir is significantly affected.

Mid-Continent Area Reliability Coordination Agreement indicated the data utilized in the report was 1978 and 1979 data and that the latest data should be used, if possible.

Chapter 7
INVENTORY

7.1 STAGE 1, 2, AND 3 RESULTS

Inventory

The preliminary inventory of potentially feasible hydropower sites, existing and undeveloped, in the MARCA region included approximately 815 sites. The major source of data on the existing dams was the National Inventory of Dams developed by the Corps of Engineers. Of the 815 MARCA sites, 595, or 73 percent, are located in the North Central Division (NCD) with the remaining 220 sites, or 27 percent, located in the Missouri River Division (MRD).

After the Stage 1 screening, which screened those sites with insufficient head and flow to produce power, 250 sites (47 in MRD and 203 in NCD) remained in active status. The remaining 565 sites were placed in the inactive file.

In Stage 2, the sites that had a potential of 1 MW or greater and a benefit-to-cost ratio greater than unity remained active and the balance was placed in the inactive file. The Stage 3 first screening was based on more detailed and refined physical and economic information. To complete this task, the data on each site was refined and additional data were compiled as needed. As a result of this screening, all sites with less than 1 MW incremental capacity and sites with B/C ratio of less than unity were placed in the inactive file. After this screening, 77 MARCA sites (19 in MRD and 58 in NCD) remained in active status. All sites with an existing capacity greater than 1 MW and with incremental capacity not economically or environmentally acceptable were carried through the remaining stages. This was done to aid in the system analysis of existing hydroelectric power in MARCA. Of the 77 active sites, 29 fall into this category. The active 77 sites were carried forward for more stringent analysis during the second screening of the third stage.

The task of the second screening, third stage, was to remove projects having overriding adverse noneconomic impacts from the active inventory. Each site was screened according to environmental, social, and institutional criteria. As a result of this screening, none of the active sites in MARCA were changed to inactive. However, three existing projects had incremental capacity which was determined environmentally and/or institutionally unacceptable, but the projects remained active since the existing capacity at each project was greater than 1 MW.

As a result of the Stages 1, 2, and 3 screenings and public participation, 77 sites in MARCA remain active. Only 48 sites, however, show feasible incremental capacity; the other 29 sites remain in the inventory solely because they each have an existing capacity greater than 1 MW. Table 7-1 summarizes the results of the 3 stages of screening.

Table 7-1
MARCA SCREENINGS FROM PRELIMINARY INVENTORY TO STAGE 4

Total Before Screening	Screening Distribution	Screening Results Active	Screening Results Inactive
	Stage 1 Screening		
	Distribution by Division		
220	MRD	47	173
595	NCD	203	392
815	Total	250	565
	Distribution by State		
321	Minnesota	107	214
140	Wisconsin	62	78
115	Nebraska	32	83
100	Iowa	36	64
79	North Dakota	2	77
34	South Dakota	8	26
26	Montana	3	23
815	Total	250	565
	Stage 2 & Stage 3 First Screening		
	Distribution by Division		
47	MRD	19(10)1/	28
203	NCD	58(16)1/	145
250	Total	77(26)1/	173
	Distribution by State		
107	Minnesota	30(8)1/	77
62	Wisconsin	22(8)1/	40
32	Nebraska	11(8)1/	21
36	Iowa	6	30
2	North Dakota	1	1
8	South Dakota	4(1)1/	4
3	Montana	3(1)1/	0
250	Total	77(26)1/	173
	Stage 3 Second Screening		
	Distribution by Division		
19	MRD	19	0
58	NCD	58	0
77(26)1/	Total	77(29)	0
	Distribution by State		
30	Minnesota	30	0
22	Wisconsin	22	0
11	Nebraska	11	0
6	Iowa	6	0
1	North Dakota	1	0
4	South Dakota	4(3)2/	0
3	Montana	3	0
77(26)1/	Total	77(29)	0

1/ The sites in the parentheses indicate the number of existing sites having no economically feasible incremental capacity but were carried through all stages as active sites because existing capacity is greater than 1 MW.

2/ The sites in parentheses indicate those sites which showed incremental capacity environmentally and institutionally unacceptable but were carried as active sites because existing capacity is greater than 1 MW.

Primary Locations

The majority of sites remaining after the Stage 3 screenings are located in the northeastern portion of MARCA. The States of Minnesota and Wisconsin contain about 68 percent of the active MARCA sites (39 percent in Minnesota and 29 percent in Wisconsin). The State of Nebraska follows with 14 percent, Iowa with 9 percent, South Dakota with 5 percent, Montana with 3 percent, and North Dakota with 1 percent. Four major rivers, three in the northeastern region of MARCA and one in the central portion, contain about 40 percent of these sites. These include 13 sites on the Mississippi River, 7 on the Chippawa River, 6 on the Missouri River, and 4 on the St. Louis River.

POTENTIAL DEVELOPMENT

The results of the Stage 1, 2, and 3 screenings indicate the 30 existing hydropower projects which have feasible additional capacity could be increased by 834 MW. The 18 existing damsites which have feasible new power additions could add an additional 212 MW to the system. The total 48 projects could add 1,046 MW of capacity and 1,654 GWH of energy to the MARCA system. In Chapter 4, the total demand for the MARCA region in 1990 was estimated as 162.6 thousand GWH, which is an increase of 70.1 thousand GWH over 1978 demands. If all 48 hydropower projects were developed by the year 1990, an additional 1,654 GWH could be added to the system. This would represent about 2 percent of the projected energy demand for MARCA in the period 1978 to 1990. It can be seen that the proposed hydropower development would not have a measurable effect on the average load characteristics for the MARCA region and that all of the proposed additions could be developed with no constraints imposed by load conditions.

Projects with existing power capabilities show the highest potential for additional hydropower development with approximately 66 percent of the active sites falling in this category. Existing projects without hydropower capabilities show a moderate potential for development with approximately 30 percent of the feasible MARCA sites included in this category. The projects with the least potential for development are new projects not yet constructed. Only 4 percent of the active MARCA sites are new projects.

Existing Projects with Power

The active sites after the Stages 1, 2, and 3 screenings include 59 existing projects currently producing power. Of the 59 projects, 30 show a potential for the development of additional capacity; the other sites remain active because they have an existing capacity greater than 1 MW. The total additional capacity which the 30 sites could provide is approximately 833.6 MW or about 80 percent of the total additional potential for MARCA.

The existing projects with power are divided into large-scale (sites with existing capacity greater than 25 MW) and small-scale (sites less than 25 MW. The active inventory after the Stages 1, 2, and 3 screenings includes six large-scale projects currently producing power which have the potential for additional capacity. The existing capacity currently generated by the six large-scale sites is 985 MW with the potential additional capacity of 530.5 MW. The active inventory also includes 24 small-scale sites currently producing 184 MW with a potential additional capacity of 303 MW. Table 7-2 shows the potential development for existing projects currently producing power, both for large and small-scale, distributed by state. The State of North Dakota shows the largest potential for large-scale existing power projects with an approximate 68 percent increase. This is followed by a 45 percent increase in Montana, and a 43 percent increase in both Minnesota and Wisconsin. The other states in MARCA show no potential increase for existing large-scale sites. Minnesota and Wisconsin will provide essentially all of the potential increase for existing small-scale power projects.

Existing Projects Without Power

Existing projects without power include those sites which have an existing dam and reservoir used for purposes other than hydropower. The potential for adding hydropower to these sites is moderate within the MARCA region; 16 projects (21 percent of the 77 active sites) of this type remained on the active list after the Stage 3 screenings. The capacity which could be added at these sites is approximately 188 MW, or about 18 percent of the total potential additional capacity for MARCA. This corresponds with an additional energy potential of 668.8 GWH. The majority of these sites are in Minnesota and Iowa, with nine and four sites, respectively. Three other states in MARCA-Nebraska, Wisconsin, and Montana, have sites of this type, with each State containing one site.

The State of Iowa is the only state in MARCA which shows large-scale hydropower potential at an existing project which currently has no hydropower facilities. A new capacity of 58 MW and energy of 116.5 GWH represent the potential at this site. The remaining 15 sites are classified as small scale. Table 7-2 shows the state distribution of potential power and energy for both large and small-scale existing projects without power.

New Sites

New sites are classified as those sites which are undeveloped and have no existing dam. There are only two such sites in the MARCA region; both are located in Nebraska. These sites are small-scale projects having a combined potential capacity of 23.7 MW, about 2 percent of the total potential capacity for MARCA. The energy associated with the potential capacity is 81.2 GWH. These sites are under study by the Water and Power Resources Service (WPRS) for irrigation and other associated uses. Since the undeveloped sites are currently being considered by the WPRS for multiple-purpose development, this study determined the feasibility of the separable hydropower features only. Table 7-2 includes these sites.

SITES DELETED DUE TO NONECONOMIC REASONS

The second screening, third stage, was designed to screen the projects having overriding adverse environmental, social, and institutional impacts. During this screening, three projects in the MARCA region were changed from

Table 7-2
MARCA STATE DISTRIBUTION OF POTENTIAL DEVELOPMENT

State	Total Sites	Total Sites With Potential Power	Existing Capacity (MW)	Potential Capacity (MW)	Existing Energy (GWH)	Potential Energy (GWH)
NEBRASKA						
Existing Projects With Power						
Large Scale	4	0	152.0	0	474.6	0
Small Scale	4	0	29.9	0	115.0	0
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	1	1	0	2.0	0	12.4
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	2	2	0	23.7	0.0	81.2
TOTAL	11	3	181.9	25.7	589.6	93.6
IOWA						
Existing Projects With Power						
Large Scale	-	-	-	-	-	-
Small Scale	2	2	4.2	5.6	16.0	20.5
Existing Projects Without Power						
Large Scale	1	1	0	58.0	0	116.5
Small Scale	3	3	0	31.8	0	75.6
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	6	6	4.2	95.4	16.0	212.6
MONTANA						
Existing Projects With Power						
Large Scale	2	1	415.0	185.0	2,019.0	-26.3
Small Scale	-	-	-	-	-	-
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	1	1	0	10.0	0	51.0
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	3	2	415.0	195.0	2,019.0	24.7
NORTH DAKOTA						
Existing Projects With Power						
Large Scale	1	1	400.0	272.0	2,270.0	-66.3
Small Scale	-	-	-	-	-	-
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	1	1	400.0	272.0	2,270.0	-66.3

Table 7-2 (cont'd)
MARCA STATE DISTRIBUTION OF POTENTIAL DEVELOPMENT

State	Total Sites	Total Sites With Potential Power	Existing Capacity (MW)	Potential Capacity (MW)	Existing Energy (GWH)	Potential Energy (GWH)
SOUTH DAKOTA						
Existing Projects With Power						
Large Scale	4	0	1,483.0	0.0	6,056.0	0
Small Scale	-	-	-	-	-	-
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	4	0	1,483.0	0.0	6,056.0	0
MINNESOTA						
Existing Projects With Power						
Large Scale	1	1	69.6	30.4	318.0	271.42
Small Scale	20	12	98.7	194.3	564.8	492.9
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	9	9	-	83.1	-	400.9
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	30	22	168.3	307.8	882.8	1165.22
WISCONSIN						
Existing Projects With Power						
Large Scale	3	3	100.0	43.1	328.3	55.3
Small Scale	18	10	119.3	103.2	557.3	157.4
Existing Projects Without Power						
Large Scale	-	-	-	-	-	-
Small Scale	1	1	0.0	4.0	0.0	12.4
New Projects						
Large Scale	-	-	-	-	-	-
Small Scale	-	-	-	-	-	-
TOTAL	22	14	219.3	150.3	885.6	225.1

active status to inactive status, they are all in South Dakota. The three sites are located on the Missouri River; they are part of the system of main stem dams operated by the Corps of Engineers. Lewis and Clark Lake (Gavins Point Dam) is the farthest downstream dam in the system. Its major function is to provide regulation of flows in the lower river for navigation, water supply, and flood control. Pronounced fluctuations in stage, associated with additional hydropower, would be incompatible with these purposes and with the authorized Missouri River Recreation Project. Therefore, Lewis and Clark Lake was considered environmentally and institutionally unacceptable. The other two dams in the main stem system, Lake Oahe (Oahe Dam) and Lake Francis Case (Fort Randall Dam), were changed to inactive status because the environmental, social, and institutional impacts associated with the additions were viewed as unacceptable. The major impacts at both sites include:

- Increased velocities and fluctuations may affect fish spawning areas;

- Decreased food supply for the American bald eagles in the Karl Mundt National Wildlife Refuge adjacent to Lake Francis Case;

- Loss of wooded areas used by eagles and wildlife at both dams;

- Reduction of sport fishing and loss of established camping and boat landing areas below the dams; and

- Wide variations existing in the extent and timing of future water depletions, which could result in operation under unrealistically low load factors.

7.2 STAGE 4 INVENTORY

There are 77 sites which comprise the MARCA Stage 4 inventory; 19 in MRD and 58 in NCD. Twenty-nine of the 77 sites have an existing capacity greater than 1 MW but additional capacity was not economically and/or environmentally acceptable. The remaining 48 sites could add a capacity of 1,046 MW and an average annual energy of 1,654 GWH to the MARCA region.

PROJECTS RETAINED DURING STAGE 4

The major tasks involved during the Stage 4 screening included the ranking of potential sites according to economic, environmental, social, and institutional criteria and the determination of hydropower systems which could meet the future demands in the MARCA region. All of the sites which passed through the Stage 3 screenings were retained through Stage 4 screenings. By the year 1990, the estimated future peak power demand in MARCA is expected to be 32.4 GW and the total energy demand 162,600 GWH. This would require an additional 14.4 GW and 70,100 GWH over 1978 demands using the median power demand projection. (See table 4-2.) The aggregate incremental capacity of all sites remaining after the Stage 3 screenings is about 1.05 GW and the potential energy is 1,654 GWH. When compared to the projected median demand (See table 4-2) by 1990 for capacity and energy, the potential afforded by new hydropower development in MARCA would meet 7 percent of the required additional capacity and only 2 percent of the additional energy required to meet the demand. None of the projects from the end of Stage 3 were rejected during the Stage 4 analysis. When the total potential hydropower development is compared to the higher utility demand, the projects would meet less than 7 percent of the required capacity for 1990 and slightly less than 1 percent of the energy requirement.

Physical Characteristics

The existing hydropower projects retained during Stage 4 included storage reservoirs (with and without existing power), run-of-river reservoirs (with and without existing power), and diversion structures with existing power. A large majority of sites, approximately 74 percent, are storage reservoirs; 22 percent are run-of-river reservoirs, and 4 percent are diversions. The net power head available at the projects has a wide range, as low as 8 feet on a run-of-river site, to as much as 368 feet at an existing reservoir. The power head available varies greatly between the MRD and NCD projects where 94 percent of the NCD sites have power heads less than 100 feet; 75 percent of the MRD sites have power heads greater than 100 feet.

Economic Characteristics

The sites retained during Stage 4 were ranked according to net benefits from highest to lowest. The range of net benefits is \$16,250 per year to \$5,584,000 per year. Table 7-3 shows the economic characteristics of all the Stage 4 sites.

Table 7-3
STAGE 4 ECONOMIC CHARACTERISTICS FOR INCREMENTAL CAPACITY

Description	Min.	Max.
Net Power Benefits (\$/year)	16,250	5,584,000
Investment Cost (\$1000)	710	83,000
Annual Energy Cost (\$/MWH)	1.9	193.4
Average Annual Cost (\$/year)	23,291	3,682,061
Average Annual Benefits (\$/year)	215,000	9,604,000
B/C Ratio	1.0	9.27
Economic Life	100 yrs.	
Discount Rate	6 7/8 %	
Cost Levels	July 1978	

It should be noted that the costs for existing projects currently producing power may be underestimated. Although the cost analysis for powerhouse expansion was computed on a general basis, the unique nature of existing powerhouse expansion presents more complex problems which were not taken into account during the generalized analysis. Further site specific analysis of each existing powerhouse may result in a higher project cost estimate.

General Environmental and Social Conditions

The second screening, third stage, analyzed sites on an environmental and social basis. At that time, those sites which were unacceptable were deleted from the active inventory. Therefore, all sites which comprise the Stage 4 inventory are considered environmentally and socially acceptable. The environmental and social impacts from the sites in the Stage 4 inventory would be minimal since about 96 percent of the sites are existing dams and 65 percent of those are existing with power. In the latter case (existing dams with power), the environmental impacts would be associated with increased discharges and resultant reservoir and downstream stage fluctuations. However, in most cases an analysis of releases required for power, flood control, navigation, water supply, recreation, and fish and wildlife can be made to meet all the necessary requirements for that project. The social impacts associated with the projects are expected to be considered minimal since a majority of the sites are existing. No serious disruption in social harmony is expected since there would be no massive relocations of transportation facilities, residences and commercial buildings.

Chapter 8
EVALUATION

8.1 REGIONAL PLAN DEVELOPMENT

Development of the regional plan consisted of an analysis and ranking of potential sites which passed through the screening process. Several alternative hydropower systems to meet the demands for electric power in the MARCA region were identified, these included: an economically optimum system, an environmentally oriented system, and a regional system.

The primary interest in system identification was given to conventional hydropower. There are no existing sites for integral pumped storage projects within the MARCA region, however, offstream pumped storage possibilities appear to be numerous, provided there is a large body of water nearby. The potential for offstream site development exists along the Missouri River upstream from Lake Francis Case. The Corps of Engineers, Omaha District, is currently studying the Missouri River for possible adjoining pumped storage sites. The District has proposed a project of this type located adjacent to Lake Francis Case in South Dakota. The potential project, Gregory County Pumped Storage, would have a capacity of over 1,000 MW. Since this project is one of the first of its kind to be considered by the Corps of Engineers, several policy aspects must be examined during ongoing studies. Evaluation of the potential project, currently underway, would result in information which would support a construction authorization. An interim report will be prepared by the end of Fiscal Year 1981. Pumped storage projects were not incorporated into development of the regional systems. Since emphasis in the National Hydroelectric Power Study is on conventional hydropower, pumped storage projects would require much more study effort than given in this regional analysis.

ECONOMICALLY OPTIMUM SYSTEM BY PROJECT

The economically optimum system included all sites regardless of adverse environmental, institutional, and social impacts associated with each site. To determine economic feasibility, the net benefits (annual benefits minus annual costs) and the benefit-cost ratios $\frac{\text{(annual benefits)}}{\text{(annual costs)}}$ for the incremental hydropower were used as determining factors. If the site had a B/C ratio less than unity and negative net benefits, the site was not feasible and was not included in the economically optimum system.

The system includes 51 sites which show feasible incremental capacity. Of these, 33 are existing hydropower sites, 16 are existing damsites with no existing power, and 2 are undeveloped sites. Forty sites are less than 25 MW and 11 are 25 MW or more. With the additional hydropower, the capacity of the system of 51 projects would increase from an existing 1.9 GW to 4.3 GW.

If all these projects were developed, the hydropower capability within MARCA would increase from 3.0 GW to 5.4 GW. The estimated peak demand for the year 1990, using the median projection from Chapter 4 is 32.4 GW. The economically optimum system could provide approximately 17 percent of the 1990 capacity demand. Table 8-1 shows the project name, state, incremental capacity, incremental energy, incremental net benefits, unit cost of incremental energy, and the benefit-cost ratio for all sites included in the economically optimum system.

ENVIRONMENTALLY ORIENTED SYSTEM BY PROJECT

The environmentally oriented system does not include sites with unacceptable environmental impacts. This system is designed to show those projects which are feasible and have no overriding environmental impacts. During the stage three, second screening, sites with unacceptable environmental impacts were deleted from the active inventory; therefore, the sites which passed through this screening represent the environmentally oriented system. Only three MARCA sites, as discussed in Chapter 7, were deleted during the stage three, second screening; Lake Francis Case, Lake Oahe, and Lewis and Clark. Therefore, the difference between the economically optimum and environmentally oriented systems is represented by the three projects. The 48 hydropower sites that comprise the environmentally oriented system would, if developed, produce an additional 1,654 GWH of electrical energy and provide an additional capacity of 1.05 GW to meet peak power demands. If the projects were developed, the energy at the 30 existing hydropower projects would increase from 4.8 thousand GWH to 6.45 thousand GWH, a 34 percent increase and capacity to meet peak demands would increase from .9 GW to 1.73 GW, a 92 percent increase. The remaining 18 feasible hydropower projects have no existing generating facilities but, if developed, would provide .74 thousand GWH of additional energy and .2 GW of additional capacity. The system of 48 sites would increase the MARCA hydropower capacity by 1.05 GW, an increase of 35 percent over 1978; and energy production could increase by 1.5 thousand GWH, an increase of about 10.6 percent over 1978.

REGIONAL SYSTEM BY PROJECT

The regional system is a combination of the economically optimum system and the environmentally oriented system. However, since three projects in MARCA were considered to have overriding noneconomic impacts and since the remaining 48 projects are considered to be acceptable from a noneconomic standpoint, the regional plan is identical with the environmental plan. Table 8-2 shows data for the projects in this system. The Appendix at the end of this report includes a table showing more detailed physical information, a map of MARCA showing the project locations, individual data sheets, and individual site maps for all projects which comprise the regional system.

Economic Aspects

Projects comprising the 48 sites in the regional system have passed through both economic and environmental screenings. The objective of the economic analysis related the project benefits to project costs. The major

Table 8-1
DATA FOR ECONOMICALLY OPTIMUM SYSTEM

State	Type of Project[1/]	Project Name	Capacity (KW)	Energy (MWH)	Net Benefits	B/C	Cost of Energy ($/MWH)
South Dakota	ESP	Lake Francis Case	484,120	621,783	$27,756,895	3.73	$ 16.35
South Dakota	ESP	Lake Oahe	612,908	-278,158	21,427,742	2.89	-
South Dakota	ESP	Lewis & Clark	278,935	189,343	9,753,014	1.95	54.48
North Dakota	ESP	Lake Sakakawea	272,000	-66,300	5,584,000	1.6	-
Minnesota	ESP	Thomson	30,400	271,423	4,198,393	9.27	1.89
Montana	ESP	Lake Fort Peck	185,000	-26,300	3,386,000	1.4	-
Minnesota	ESP	Rainy Lake	59,097	190,306	2,118,091	1.50	22.21
Iowa	ES	Red Rock	57,916	116,534	1,419,108	1.38	31.60
Wisconsin	EDP	Jim Falls	43,304	60,248	1,412,248	1.69	33.68
Minnesota	ER	Coon Rapids	16,161	82,663	930,239	1.74	15.09
Minnesota	ES	Kettle Falls	14,963	90,478	925,787	1.66	15.30
Minnesota	ERP	Hennepin 1	9,899	53,404	772,463	2.78	8.13
Iowa	ER	Saylorville	17,267	44,319	695,346	1.72	21.71
Minnesota	ERP	Lower Dam	13,570	53,622	663,647	1.82	14.97
Wisconsin	ESP	Wissota	30,383	28,271	646,561	1.45	50.35
Minnesota	ESP	Sartell	12,994	48,101	565,039	1.61	19.18
Minnesota	ESP	Blanchard	56,280	44,404	507,122	1.15	74.43
Wisconsin	EDP	Dells 1907	16,255	34,391	490,932	1.49	28.71
Minnesota	ESP	Cloquet	18,078	18,898	458,460	1.49	48.59
Montana	ER	Yellowtail Afterbay	10,000	51,800	374,207	1.38	18.82
Minnesota	ES	Lock 5	5,808	45,041	293,973	1.37	17.65
Minnesota	ESP	Fond Du Lac	5,134	18,336	268,104	2.00	14.61
Wisconsin	ESP	Big Falls	7,364	7,750	258,781	1.83	39.98
Wisconsin	ESP	Hatfield	12,523	19,851	254,240	1.32	39.31
Minnesota	ERP	Lock 1	1,932	19,146	234,693	3.91	4.20
Minnesota	ERP	Brainerd	6,953	23,988	229,835	1.44	21.68
Wisconsin	ESP	Holcombe 2	5,264	14,847	224,172	1.75	19.94
Iowa	ES	Coralville	11,632	25,734	206,337	1.23	33.62

Table 8-1 (cont'd)
DATA FOR ECONOMICALLY OPTIMUM SYSTEM

State	Type of Project[1/]	Project Name	Capacity (KW)	Energy (MWH)	Net Benefits	B/C	Cost of Energy ($/MWH)
Minnesota	EX	Cannon River	6,928	12,850	$ 206,069	1.54	$ 29.65
Wisconsin	ESP	Arpin	3,916	11,643	197,578	1.99	16.99
Minnesota	ER	St. Cloud	10,990	42,747	198,895	1.17	26.93
Minnesota	ER	Lock 2	4,919	32,721	173,309	1.26	20.12
Wisconsin	ESP	Chippewa Falls	2,343	9,286	151,350	2.19	13.65
Wisconsin	ESP	Cornell 19	7,446	12,233	142,815	1.32	36.41
Wisconsin	ESP	Flambeau 2	2,487	2,806	113,876	1.92	43.74
Iowa	ERP	733 IA	1,542	11,803	109,708	2.04	8.94
Wisconsin	ESP	Cedar Falls	8,957	2,278	101,050	1.22	193.38
Minnesota	ER	Lock 7	12,685	64,668	99,673	1.06	25.36
Wisconsin	ESP	White River 1	3,763	64,668	94,269	1.54	45.02
Minnesota	ESP	Sylvan	3,694	3,860	92,036	1.37	30.52
Iowa	ERP	719 IA	4,143	8,005	91,088	1.34	30.20
Minnesota	ESP	Blandin	3,177	8,692	87,195	1.40	28.55
Minnesota	ER	Rapidan	5,838	7,521	83,545	1.14	28.17
Wisconsin	ES	Island Lake	4,815	9,645	71,050	1.20	36.60
Nebraska	ES	Merritt Res.	2,040	12,381	49,643	1.20	19.17
Wisconsin	ES	Chippewa	4,040	12,431	49,215	1.12	30.69
Minnesota	ERA	Pisgah	3,458	6,185	42,220	1.17	39.16
Wisconsin	ESP	Ladysmith	2,248	5,263	32,606	1.17	35.61
Iowa	ER	232 IA	2,976	5,625	16,250	1.06	42.27
Nebraska	U	Norden	21,992	70,116	1,579,332	2.44	15.56
Nebraska	U	Calamus	1,652	11,114	109,208	1.49	19.79

[1/] Code for Type of Project
E = Existing Project
P - Project Currently Producing Power
D - Diversion Project
U - Undeveloped Project
X - Retired Power Plant
R - Run of River Project
S - Reservoir Storage Project

Table 8-2
DATA FOR ENVIRONMENTALLY ORIENTED SYSTEM

State	Type of Project[1/]	Project Name	Capacity (KW)	Energy (MWH)	Net Benefits	B/C	Cost of Energy ($/MWH)
North Dakota	ESP	Lake Sakakawea	272,000	-66,300	$ 5,584,000	1.6	$ -
Minnesota	ESP	Thomson	30,400	271,423	4,198,393	9.27	1.87
Montana	ESP	Lake Fort Peck	185,000	-26,300	3,386,000	1.4	-
Minnesota	ESP	Rainy Lake	59,097	190,306	2,118,091	1.50	22.21
Iowa	ES	Red Rock	57,916	116,534	1,419,108	1.38	31.60
Wisconsin	EDP	Jim Falls	43,304	60,248	1,412,248	1.69	33.68
Minnesota	ER	Coon Rapids	16,161	82,663	930,239	1.74	15.09
Minnesota	ES	Kettle Falls	14,963	90,478	925,787	1.66	15.30
Minnesota	ERP	Hennepin 1	9,899	53,404	772,463	2.78	8.13
Iowa	ER	Saylorville	17,267	44,319	695,346	1.72	21.71
Minnesota	ERP	Lower Dam	13,570	53,622	663,647	1.82	14.97
Wisconsin	ESP	Wissota	30,383	28,271	646,561	1.45	50.35
Minnesota	ESP	Sartell	12,994	48,101	565,039	1.61	19.18
Minnesota	ESP	Blanchard	56,280	44,404	507,122	1.15	74.43
Wisconsin	EDP	Dells 1907	16,255	34,391	490,932	1.49	28.71
Minnesota	ESP	Cloquet	18,078	18,898	458,460	1.49	48.59
Montana	ER	Yellowtail Afterbay	10,000	51,800	374,207	1.38	18.82
Minnesota	ES	Lock 5	5,808	45,041	293,973	1.37	17.65
Minnesota	ESP	Fond Du Lac	5,134	18,336	268,104	2.00	14.61
Wisconsin	ESP	Big Falls	7,364	7,750	258,781	1.83	39.98
Wisconsin	ESP	Hatfield	12,523	19,851	254,240	1.32	39.31
Minnesota	ERP	Lock 1	1,932	19,146	234,693	3.91	4.20
Minnesota	ERP	Brainerd	6,953	23,988	229,835	1.44	21.68
Wisconsin	ESP	Holcombe 2	5,264	14,847	224,172	1.75	19.94
Iowa	ES	Coralville	11,632	25,734	206,337	1.23	33.62

Table 8-2 (cont'd)
DATA FOR ENVIRONMENTALLY ORIENTED SYSTEM

State	Type of Project[1]	Project Name	Capacity (KW)	Energy (MWH)	Net Benefits	B/C	Cost of Energy ($/MWH)
Minnesota	EX	Cannon River	6,928	12,850	$ 206,069	1.54	$ 29.65
Wisconsin	ESP	Arpin	3,916	11,643	197,578	1.99	16.99
Minnesota	ER	St. Cloud	10,990	42,747	198,895	1.17	26.93
Minnesota	ER	Lock 2	4,919	32,721	173,309	1.26	20.12
Wisconsin	ESP	Chippewa Falls	2,343	9,286	151,350	2.19	13.65
Wisconsin	ESP	Cornell 19	7,446	12,233	142,815	1.32	36.41
Wisconsin	ESP	Flambeau 2	2,487	2,806	113,876	1.92	43.74
Iowa	ERP	733 IA	1,542	11,803	109,708	2.04	8.94
Wisconsin	ESP	Cedar Falls	8,957	2,278	101,050	1.22	193.38
Minnesota	ER	Lock 7	12,685	64,668	99,673	1.06	25.36
Wisconsin	ESP	White River 1	3,763	64,668	94,269	1.54	45.02
Minnesota	ESP	Sylvan	3,694	3,860	92,036	1.37	30.52
Iowa	ERP	719 IA	4,143	8,005	91,088	1.34	30.20
Minnesota	ESP	Blandin	3,177	8,692	87,195	1.40	28.55
Minnesota	ER	Rapidan	5,838	7,521	83,545	1.14	28.17
Wisconsin	ES	Island Lake	4,815	9,645	71,050	1.20	36.60
Nebraska	ES	Merritt Res.	2,040	12,381	49,643	1.20	19.17
Wisconsin	ES	Chippewa	4,040	12,431	49,215	1.12	30.69
Minnesota	ERA	Pisgah	3,458	6,185	42,220	1.17	39.16
Wisconsin	ESP	Ladysmith	2,248	5,263	32,606	1.17	35.61
Iowa	ER	232 IA	2,976	5,625	16,250	1.06	42.27
Nebraska	U	Norden	21,992	70,116	1,579,332	2.44	15.56
Nebraska	U	Calamus	1,652	11,114	109,208	1.49	19.79

[1] Code for Type of Project
E = Existing Project
P - Project Currently Producing Power
D - Diversion Project
U - Undeveloped Project
R - Run of River Project
S - Reservoir Storage Project

goal of this analysis was to determine the capacity at which net benefits were optimized for each project.

In order to formulate the potential hydropower project in an efficient manner, with the least amount of the Nation's resources used, the cost for the cheapest alternative power project that could be developed in lieu of the considered project was used as a basis for benefits. When the benefits are limited by the cost of the cheapest alternative, a benefit-cost ratio greater than unity can only occur if the cost of the considered project is smaller than the cost of the alternative. The degree to which the benefit-cost ratio exceeds unity indicates the relative advantage of the project over its alternative.

Annual costs and benefits were determined utilizing; computer routines incorporating 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, an Institute for Water Resources publication, provides the basic cost estimating criteria used in 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 10 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.

Table 8-1 shows the economic data, B/C ratio, net benefits, and unit cost of energy ($/MWH) for each project in the regional system. The table shows that generally projects with a large additional capacity have high net benefits. In some cases, the negative energy values are the result of a reduction in average annual energy caused by the higher tailwater associated with large capacities.

Impacts

Since all but two of the projects 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 elevation 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. The greater impacts would result from the two undeveloped sites in Nebraska - Calamus and Norden. Since these dams are currently under study by the Water and Power Resources Service, the environmental impacts are not known. There currently is considerable controversy over the impacts and safety of the proposed Norden Dam. At the completion of the Water Power Resources Service study, if either or both projects are found to be environmentally, institutionally, or socially unacceptable, they should be dropped from further consideration under the National Hydroelectric Power Study.

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 existing dam features, since 46 of the 48 sites that comprise the regional system are existing dams. The analysis on these sites assumed additional hydropower would be added with essentially no costs included for major alterations to the existing features. Thus, the existing head and storage capabilities associated with the dam will limit the additional capacities. A second major physical constraint would be the ability of the added power function to coincide with the existing purpose of the projects; for example, new hydropower releases at existing irrigation, navigation, water supply, hydropower, flood control, and diversion projects. The analysis of the sites included in the regional system assumed 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 streams below the projects. The former would be more important for the two undeveloped sites rather than for the existing projects. There should be no major social constraints on the existing projects since most operate within specified parameters, maintaining allowable releases. The discharge associated with the existing and additional capacities, along with other project uses, would be limited to allowable maximum and minimum releases.

The major institutional constraint would be the existing state water laws for each project. This would have a major impact on the two undeveloped sites and may affect some of the existing projects. An analysis of the water laws governing each project would be needed before the bounds of this constraint would be known. This analysis was not included in this study.

8.2 SCHEDULE FOR DEVELOPMENT

Since all of the 48 projects could not be developed at the same time, or at least it would seem improbable for this to occur, a logical order would be appropriate for determining those projects which should be pursued prior to any others and a time frame 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 MARCA existing and projected capacity and energy demands. Since there is a need for a large amount of capacity to meet summer peak loads in MARCA, the order of preference has been given to capacity rather than energy. Projects were sized according to net benefit maximization. Because there is a correlation between net benefit and dependable capacity, and since net benefits indicate those projects which have a greater relative advantage over the alternative project with equal capacities, preference was given to those projects having the highest incremental net benefits. For purposes of this study, projects were divided into two time frames - near-term and long-term. Near-term are projects that could be developed before 1990, and long-term to sites that could be developed after 1990. In the 10-year period between 1980 and 1990, hydropower could be added to the sites with existing features. The 10-year period would give enough time to complete a study and construct the hydropower facilities at existing dams but not enough time to complete the extensive study and construction which would be associated with an undeveloped site. Some of the time consuming elements that would cause the need for additional time at an undeveloped site would include obtaining water rights, acquiring land, analysis of multiple purpose facilities, preparation of environmental impact statements, and obtaining public acceptance of project.

NEAR-TERM

Near-term projects, as stated above, include projects that could be developed before 1990. All projects with existing dams fall into this category, (46 projects in the regional system.) Table 8-3 shows the state, project name, and incremental capacity for the near-term regional system projects. These have been ranked by incremental net benefits, the site with the highest net benefits being the most desirable project.

LONG-TERM

Long-term projects are those sites which cannot be developed before 1990, (all undeveloped sites.) Two projects within the regional system fall into this category - Calamus and Norden in Nebraska; both projects are currently being studied by the Water and Power Resources Service. Table 8-4 shows the state, project name, and new potential capacity for the long-term regional system by project. The two projects were ranked by incremental net benefits.

Table 8-3
SHORT TERM REGIONAL SYSTEM RANKED
MOST TO LEAST DESIRABLE PROJECT

State	Project Name	Name of Stream	Incremental Capacity (KW)
North Dakota	Lake Sakakawea	Missouri	272,000
Minnesota	Thomson	St. Louis	30,400
Minnesota	Lock 7	Mississippi	12,685
Montana	Lake Fort peck	Missouri	185,000
Minnesota	Rainy Lake	Rainy River	59,097
Iowa	Red Rock	Des Moines	57,916
Wisconsin	Jim Falls	Chippewa	43,304
Minnesota	Lock 5	Mississippi	5,808
Minnesota	Coon Rapids	Mississippi	16,161
Minnesota	Kettle Falls	Rainy River	14,963
Minnesota	Hennepin 1	Mississippi	9,899
Iowa	Saylorville	Des Moines	17,267
Minnesota	Lower Dam	Mississippi	13,570
Wisconsin	Wissota	Chippewa	30,383
Minnesota	Sartell	Mississippi	12,994
Minnesota	Blanchard	Mississippi	56,280
Wisconsin	Dells 1907	Chippewa	16,255
Minnesota	Cloquet	St. Louis	18,078
Montana	Yellowtail Afterbay	Big Horn	10,000
Minnesota	Fond Du Lac	St. Louis	5,134
Wisconsin	Big Falls	Flambeau	7,364
Wisconsin	Hatfield	Black	12,523
Minnesota	Lock 1	Mississippi	1,932
Minnesota	Brainerd	Mississippi	6,953
Wisconsin	Holcombe 2	Chippewa	5,264
Iowa	Coralville	Iowa River	11,632
Minnesota	Cannon River	Cannon River	6,928
Wisconsin	Arpin	Chippewa	3,916
Minnesota	St. Cloud	Mississippi	10,990
Minnesota	Lock 2	Mississippi	4,919
Wisconsin	Chippewa Falls	Chippewa	2,343
Wisconsin	Cornell 19	Chippewa	7,446
Wisconsin	Flambeau 2	Flambeau	2,487
Iowa	733 IA	Des Moines	1,542
Wisconsin	Cedar Falls	Red Cedar	8,957
Wisconsin	White River 1	White	3,763
Minnesota	Sylvan	Crow Wing	3,694
Iowa	719 IA	South Fork	4,143
Minnesota	Blandin	Mississippi	3,177
Minnesota	Rapidan	Blue Earth	5,838

Table 8-3 (cont'd)
SHORT TERM REGIONAL SYSTEM RANKED
MOST TO LEAST DESIRABLE PROJECT

State	Project Name	Name of Stream	Incremental Capacity (KW)
Minnesota	Island Lake	Cloquet	4,815
Nebraska	Merritt Res.	Snake River	2,040
Wisconsin	Chippewa	Chippewa	4,040
Minnesota	Pisgah	Ottertail	3,458
Wisconsin	Ladysmith	Flambeau	2,248
Iowa	232 IA	Middle Racoon	2,976

Table 8-4
LONG TERM REGIONAL SYSTEM RANKED
MOST TO LEAST DESIRABLE PROJECT

State	Project Name	Name of Stream	New Potential Capacity (KW)
Nebraska	Norden	Niobrara	21,992
Nebraska	Calamus	Calamus River	1,652

APPENDICES

APPENDIX

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.

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

BENEFIT-COST RATIO (B/C) - the increase in economic value produced by the hydropower addition project, typically represented as a time stream of value produced 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 load a turbine-generator station can carry under specified conditions for a given period of time.

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 - that 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.

GIGAWATT (GW) - one million kilowatts.

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

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

MEGAWATT (MW) - one thousand kilowatts.

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

NUCLEAR ENERGY - energy produced largely in the form of heat during nuclear reactions which, with conventional generating equipment, can be transformed into electrical 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 POOL - two or more electric systems which are interconnected and coordinated 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 which 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 peak 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.

RUN OF RIVER PLANT. - hydroelectric plant using the flow of the stream as it occurs and having little or no reservoir capacity for storage of water.

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.

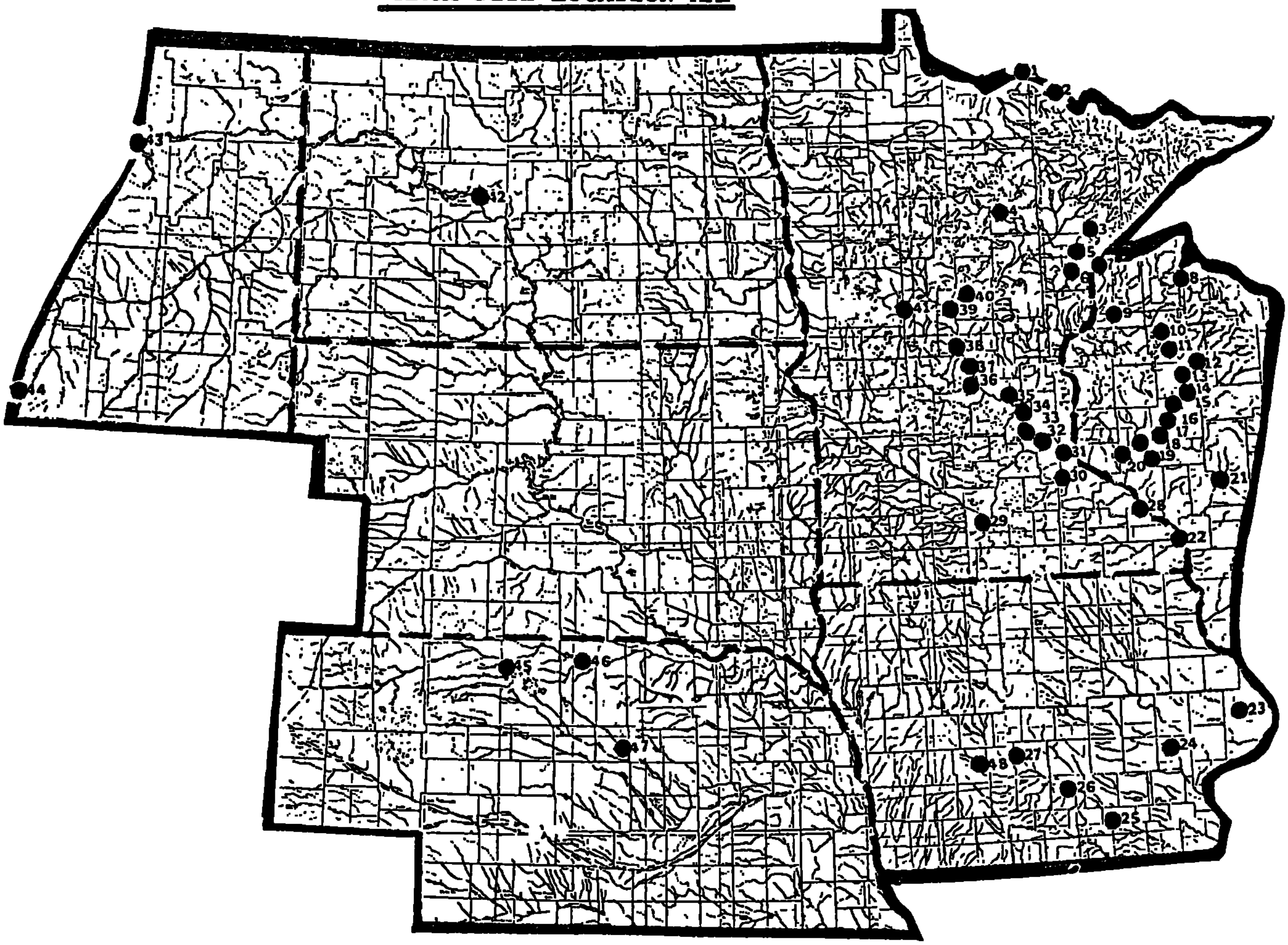
THERMAL WATER POLLUTION - rise in temperature of water such as that resulting from heat released by a thermal plant to the cooling water when the effects on other uses of the water are detrimental.

TRANSMISSION - an 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 equivalent to one ampere under a pressure of one volt at unity power factor.

MARCA SITE LOCATION MAP



NO. SITE

1. RAINY LAKE
2. KETTLE FALLS
3. ISLAND LAKE
4. BLANDIN
5. CLOQUET
6. THOMSON
7. FON DU LAC
8. WHITE RIVER
9. CORNELL 19
10. CHIPPEWA
11. ARPIN
12. BIG FALLS
13. LADYSMITH
14. FLAMBEAU 2
15. HOLCOMBE 2
16. JIM FALLS
17. WISSOTA WP
18. CHIPPEWA FALLS
19. DELLS 1907
20. CEDAR FALLS
21. HATFIELD
22. LOCK 7
23. 719 IA NO
24. CORALVILLE
25. 733 IA NO
26. RED ROCK
27. SAYLORVILLE
28. LOCK 5
29. RAPIDAN
30. CANNON RIVER
31. LOCK 2
32. LOCK 1
33. LOWER DAM
34. HENNEPIN I
35. COON RAPID

ST. CLOUD

37. SARTELL
38. BLANCHARD
39. SYLVAN
40. BRAINERD
41. PISGAH
42. LAKE SAKAKAWEA
43. LAKE FORT PECK
44. YELLOWTAIL AFTERB
45. MERRITT
46. NORDEN
47. CALAMUS
48. 232 IA NO

SITE ID	PROJECT NAME	LATITUDE	PROJ.PURP.	DAM HT	EXIST.CAP.	EXIST.ENRG	ANUL. COST	ERC ECONOMIC
NUMBER	PRIMARY CO. -NAME OF STREAM	LONGITUDE	STATUS	MX.STOR.	INC. CAP.	INC.ENERGY	ENERGY COST	ERC NONECONOMIC
ACTV. INV.	OWNER	DR.AREA	AVE. Q	PWR. HD.	TOT. CAP.	TOT.ENERGY		ERC COMPOSITE
		(D M.M)		(FT)	(KW)	(MWH)	(1000 $)	(SEQUENCE RANK)
		(D M.M)		(AC FT)	(KW)	(MWH)	($/MWH)	(SEQUENCE RANK)
		(SQ.MI)	(CFS)	(FT)	(KW)	(MWH)		(SEQUENCE RANK)
IAGNCR0027	232 IA NO	41 41.8	R	68.0	0	0	237.79	1903
1	GUTHRIE MIDDLE RACCOO	94 22.9	SI	23700	2976	5625	42.274	1903
	MID-IOWA LAKES CORP.	434	-204.8	57.9	2976	5625		1903
IAGNCR0037	719 IA NO	42 4.1	RH	25.0	1200	5000	262.47	1925
1	JACKSON SOUTH FORKMAQ	90 41.8	SI	1206	4143	8692	30.196	1925
	IA ELEC LIGHT + POWER CO	1550	-1046.2	24.9	5343	13692		1925
IACNCR0040	CORALVILLEDAM + RES ERVOIR	41 43.4	CR	132.0	0	0	865.13	1948
1	JOHNSON IOWA RIVER	91 31.6	OP	585000	11632	25734	33.617	1948
	DAEN NCR	3084	-1569.7	28.5	11632	25734		1948
IACNCR0050	RED ROCK DAM + LAKE RED ROCK	41 22.1	CR	118.0	0	0	3682.0	1978
1	MARION DES MOINESRIV	92 58.5	OP	1830000	57916	116534	31.596	1978
	DAEN NCR	12323	-4672.6	43.9	57916	116534		1978
IACNCR0100	SAYLORVILLE LAKE + DAM	41 38.0	CR	105.0	0	0	962.10	1968
1	POLK DES MOINESRIV	93 47.0	OP	676000	17267	44316	21.709	1968
	DAEN NCR	5823	-2252.4	41.9	17267	44316		1968
IAGNCR0062	733 IA NO	41 0.9	SH	14.0	3000	11000	105.48	1935
1	WAPELLO DES MOINESRIV	92 24.8	SI	4525	1542	11803	8.9368	1935
	CITY OF OTTUMWA	13200	-5057.6	14.9	4542	22803		1935

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER	LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. (KW) / INC. CAP. (KW) / TOT. CAP. (KW)	EXIST.ENRG (MWH) / INC.ENERGY (MWH) / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC / ERC NONECONOMIC / ERC COMPOSITE (SEQUENCE RANK)
MNANCS0020	RAPIDAN	44 5.5	R,H	82.5	0	0	567.16	1922
2	BLUE EARTH BLUE EARTHRIV	94 6.4	OP	13469	5838	20134	28.168	1922
	BLUE EARTHCOUNTY	2430	826.0	72.4	5838	20134		1922
MNINCS0021	CLOQUET	46 43.2	H	45.0	3500	29670	918.29	1959
2	CARLTON ST. LOUIS	92 25.6	OP	730	18078	18898	48.590	1959
	NORTHWEST PAPER CO.	3430	2217.0	36.0	21578	48568		1959
MNINCS0022	FOND DU LAC	46 39.8	H	95.0	12000	63268	267.81	1954
2	CARLTON ST LOUIS	92 17.6	OP	2100	5134	18336	14.605	1954
	MINN PWR +LT CO	3600	2347.0	78.0	17134	81604		1954
MNINCS0023	THOMSON	46 39.8	H	30.0	69600	318000	507.55	1996
2	CARLTON ST LOUIS	92 24.4	OP	4192	30400	271422	1.8699	1996
	MINN PWR +LT CO	3560	2321.0	368.0	100000	589422		1996
MNINCS0031	SYLVAN	46 18.3	H,R	45.0	1800	9800	244.33	1926
2	CASS CROW WING	94 22.7	OP	10140	3694	8005	30.521	1926
	MINNESOTA PWR + LT CO	3575	1681.0	22.0	5494	17805		1926
MNGNCS0047	BRAINERD	46 22.6	H,R	30.0	3342	16620	520.11	1950
2	CROW WING MISSISSIPPI	94 11.0	OP	16300	6953	23988	21.681	1950
	NORTHWEST PAPER CO	7320	2589.0	20.0	10295	40608		1950
MNANCS0990	LOCK 2 HASTINGS, MN	44 45.5	N	30.0	0	0	658.32	1944
2	DAKOTA MISSISSIPPI R	92 52.0	OP	240000	4919	32721	20.119	1944
	DAEN NCS	36990	10313.0	10.8	4919	32721		1944
MNMNCS0048	CANNON RIVER	44 30.7	R	62.5	0	0	381. 1	1947
2	FILLMORE CANNON RIVER	92 56.4	OP	25000	6928	12850	29.649	1947
	DAKOTA + GOODHUE COUNTY	1116	414.0	55.7	6928	12850		1947
MNANCS0050	COON RAPIDS	45 8.6	R	29.0	0	0	1247.4	1972
2	HENNEPIN MISSISSIPPI R	93 18.6	OP	2000	16161	82663	15. 91	1972
	HENNEPIN COUNTY PARKRESERVE	19100	7366.0	23.2	16161	82663		1972

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER	LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. / INC. CAP. / TOT. CAP. (KW)	EXIST.ENRG / INC.ENERGY / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC / ERC NONECONOMIC / ERC COMPOSITE (SEQUENCE RANK)
MNGNCS0992	HENNEPIN IS. /ST ANTHONY FAL	44 58.8	H	20.0	12400	91500	433.92	1969
2	HENNEPIN MISSISSIPPI R	93 15.4	OP	4900	9899	53404	8.1252	1969
	DAEN NCS	19680	7400.0	49.0	22299	144904		1969
MNGNCS0991	LOCK 1 MPLS-ST PAUL, MN	44 54.8	H	0	14400	87000	80.444	1951
2	HENNEPIN MISSISSIPPI R	93 12.1	OP	9300	1932	19146	4.2016	1951
	DAEN NCS	19684	7500.0	35.9	16332	106146		1951
MNGNCS0051	LOWER DAM , ST. ANTHONY FAL	44 58.2	HN	24.8	8000	49300	802.78	1967
2	HENNEPIN MISSISSIPPI	93 14.8	OP	420	13570	53622	14.971	1967
	NO. STATESPOWER CO.	19680	7405.0	26.9	21570	102922		1967
MNINCS0059	BLANDIN	47 13.8	H	0	2100	10000	214.70	1923
2	ITASCA MISSISSIPPI	93 31.8	OP	10430	3177	7521	28.545	1923
	BLANDIN PAPER CO	3370	1140.0	20.0	5277	17521		1923
MNINCS0074	RAINY LAKE	48 36.3	H	40.0	5600	25000	4226.8	1985
2	KOOCHICHING RAINY RIVER	93 24.0	OP	4000000	59097	190306	22.210	1985
	BOISE-CASCADE CORPORATION	15176	9387.0	32.4	64697	215306		1985
MNINCS0100	BLANCHARD	45 51.5	H	62.0	12000	79100	3305.1	1962
2	MORRISON MISSISSIPPI	94 20.4	OP	15500	56280	44404	74.433	1962
	MN PWR + LT CO	11425	3176.0	45.0	68280	123504		1962
MNGNCS0334	PISGAH	46 16.8	H	33.0	520	3600	241.95	1912
5	OTTERTAIL OTTERTAIL	95 06.1	OP	250	3458	6185	39.115	1912
	OTTERTAIL POWER CO	1250	-570.2	27.0	3978	9785		1912
MNCNCS0132	ISLAND LAKE	46 59.4	O	60.0	0	0	353. 9	1918
2	ST LOUIS CLOQUET	92 13.4	OP	196340	4815	9645	36.606	1918
	MINN PWR +LT CO	546	-441.6	37.0	4815	9645		1918
MNCNCS0123	KETTLE FALLS	48 30.0	S	26.0	0	0	1383.9	1971
2	ST LOUIS TR-RAINY RIVE	92 38.2	OP	702500	14963	90478	15.295	1971
	MN AND ONTARIO POWERCO.	13993	8656.0	18.0	14963	90478		1971

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER	LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. (KW) / INC. CAP. (KW) / TOT. CAP. (KW)	EXIST.ENRG (MWH) / INC.ENERGY (MWH) / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC (SEQUENCE RANK) / ERC NONECONOMIC (SEQUENCE RANK) / ERC COMPOSITE (SEQUENCE RANK)
MNINCS0136	SARTELL	45 37.1	H	31.5	3172	10000	922.68	1964
2	STEARNS MISSISSIPPI	94 12.1	OP	28000	12994	48101	19.182	1964
	ST. REGIS PAPER CO.	12265	4716.0	22.1	16166	58101		1964
MNANCS0330	ST CLOUD DAM	45 32.8	S	35.5	0	0	1151.0	1945
5	STEARNS MISSISSIPPI	94 08.8	OP	700	10990	42747	26.926	1945
	CITY OF	13320	-5018.1	15.9	10990	42747		1945
MNCNCS9008	LOCK 5 MINNESOTA CITY, MN	44 9.6	N	30.0	0	0	794.96	1956
2	WINONA MISSISSIPPI	91 48.6	OP	106600	5807	45041	17.649	1956
	DAEN NCS	58845	25119.0	5.0	5807	45041		1956
MNANCS9006	LOCK 7 LA CRESCENT, MN	43 51.9	N	27.5	0	0	1640.0	1929
5	WINONA MISSISSIPPI	91 18.5	OP	105000	12685	64668	25.361	1929
	DAEN NCS	62340	27900.0	5.9	12685	64668		1929

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER	LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. (KW) / INC. CAP. (KW) / TOT. CAP. (KW)	EXIST.ENRG (MWH) / INC.ENERGY (MWH) / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC (SEQUENCE RANK) / ERC NONECONOMIC (SEQUENCE RANK) / ERC COMPOSITE (SEQUENCE RANK)
MTAMRC0660	YELLOWTAILAFTERBAY	45 18.7	O	32.0	0	0	974.74	1991
2	BIG HORN BIGHORN RIVER	107 55.0	OP	520	10000	51800	18.817	1991
	DOI WPRS	19667	3494.0	17.6	10000	51800		1991
MTIMRC0144	LAKE FORT PECK	47 59.0	C H I	220.0	165000	1019000	3501.8	1995
2	GARFIELD MISSOURI RIV	106 24.0	OP	19100000	185000	-26300	133.14	1995
	DAEN MRO	57500	-8911.6	198.8	350000	992700		1995

SITE ID NUMBER ACTV. INV.	PROJECT NAME PRIMARY CO. -NAME OF STREAM OWNER	LATITUDE (D M.M) LONGITUDE (D M.M) DR.AREA (SQ.MI)	PROJ.PURP. STATUS AVE. Q (CFS)	DAM HT (FT) MX.STOR. (AC FT) PWR. HD. (FT)	EXIST.CAP. (KW) INC. CAP. (KW) TOT. CAP. (KW)	EXIST.ENRG (MWH) INC.ENERGY (MWH) TOT.ENERGY (MWH)	ANUL. COST (1000 $) ENERGY COST ($/MWH)	ERC ECONOMIC (SEQUENCE RANK) ERC NONECONOMIC (SEQUENCE RANK) ERC COMPOSITE (SEQUENCE RANK)
NDIMRC0258	LAKE SAKAKAWEA	47 30.1	CHINR	194.0	400000	2270000	5192.2	1999
2	MCLEAN MISSOURI RIVE	101 25.9	OP	24400000	272000	-66300	78.314	1999
	DAEN MRO	181400	-21474.5	173.0	672000	2203700		1999

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER	LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. (KW) / INC. CAP. (KW) / TOT. CAP. (KW)	EXIST.ENRG (MWH) / INC.ENERGY (MWH) / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC (SEQUENCE RANK) / FRC NONECONOMIC (SEQUENCE RANK) / ERC COMPOSITE (SEQUENCE RANK)
NECMRC0240	NORDEN	42 28.2	IR	180.0	0	0	1091.3	2998
2	BROWN . NIOBRARA RIVE	100 0.0	SI	411000	21992	70116	15.564	2998
	WPRS	8390	934.0	169.8	21992	70116		2998
NECMRC0209	MERRITT RESERVOIR	42 38.0	IR	115.0	0	0	237.39	1915
2	CHERRY SNAKE RIVER	100 52.3	OP	86100	2040	12381	19.173	1915
	DOI USBR	620	244.0	106.9	2040	12381		1915
NECMRC0247	CALAMUS	41 49.9	IR	85.0	0	0	219.98	2997
2	GARFIELD CALAMUS RIVER	99 12.4	SI	128200	1652	11114	19.793	2997
	WPRS	1260	300.0	74.9	1652	11114		2997

SITE ID	PROJECT NAME	LATITUDE (D M.M)	PROJ.PURP.	DAM HT (FT)	EXIST.CAP. (KW)	EXIST.ENRG (MWH)	ANUL. COST (1000 $)	ERC ECONOMIC (SEQUENCE RANK)
NUMBER	PRIMARY CO. -NAME OF STREAM	LONGITUDE (D M.M)	STATUS	MX.STOR. (AC FT)	INC. CAP. (KW)	INC.ENERGY (MWH)	ENERGY COST ($/MWH)	ERC NONECONOMIC (SEQUENCE RANK)
ACTV. INV.	OWNER	DR.AREA (SQ.MI)	AVE. Q (CFS)	PWR. HD. (FT)	TOT. CAP. (KW)	TOT.ENERGY (MWH)		ERC COMPOSITE (SEQUENCE RANK)
WIINCS0196	WHITE R. 1893C99	46 29.9	HR	26.5	1000	4900	173.78	1928
2	ASHLAND WHITE	90 54.4	OP	670	3763	3860	45. 16	1928
	LAKE SUPERIOR DIST PWR	320	280.0	49.9	4763	8760		1928
WIINCS0212	CHIPPEWA FALLS WP304	44 55.8	HR	30.0	21600	73500	126.76	1941
2	CHIPPEWA CHIPPEWA	91 23.2	OP	4800	2343	9286	13.650	1941
	NORTHERN STATES POWER CO	5550	5042.0	30.0	23943	82786		1941
WIINCS0980	CORNELL 1903C178	45 09.8	H	48.0	30900	87000	445.39	1939
2	CHIPPEWA CHIPPEWA	91 09.5	OP	22280	7448	12233	36.407	1939
	NORTHERN STATES POWER CO.	4860	851.0	37.9	38348	99233		1939
WIINCS0213	HOLCOMBE 2WP723	45 13.4	HR	57.0	33750	99715	296. 3	1949
2	CHIPPEWA CHIPPEWA	91 7.7	OP	72000	5264	14847	19.938	1949
	NORTHERN STATES POWER CO	4700	3960.0	45.0	39014	114562		1949
WIJNCS0979	JIM FALLS 1903C172	45 03.5	H,R	65.0	14400	82849	2029.4	1977
2	CHIPPEWA CHIPPEWA	91 16.0	OP	21450	43304	60248	33.684	1977
	NORTHERN STATES POWER CO.	4891	2891.0	53.9	57704	143097		1977
WIINCS0211	WISSOTA WP37	44 56.2	HR	57.0	35280	141600	1423.3	1966
2	CHIPPEWA CHIPPEWA	91 20.4	OP	226340	30383	28271	50.345	1966
	NORTHERN STATES POWER CO	5548	4943.0	57.0	65663	169871		1966
WIINCS0221	CEDAR FALLS 1883C3	44 52.6	H	60.0	6000	29100	440.69	1931
2	DUNN RED CEDAR	91 55.8	OP	12000	8957	2278	193.38	1931
	NORTHERN STATES POWER CO	1690	1065.0	42.7	14957	31378		1931
WIJNCS9033	DELLS 1907C35	44 49.5	HR	31.0	8400	43835	987.30	1961
2	EAU CLAIRE CHIPPEWA	91 30.7	OP	12000	16255	34391	28.707	1961
	CITY OF EAU CLAIRE	5752	5179.0	26.9	24655	78226		1961
WIINCS0233	HATFIELD	44 24.6	HR	0	3840	16000	780.26	1952
2	JACKSON BLACK	90 43.3	OP	23400	12523	19851	39.305	1952
		1326	993.0	90.0	16363	35851		1952

SITE ID / NUMBER / ACTV. INV.	PROJECT NAME / PRIMARY CO. -NAME OF STREAM / OWNER		LATITUDE (D M.M) / LONGITUDE (D M.M) / DR.AREA (SQ.MI)	PROJ.PURP. / STATUS / AVE. Q (CFS)	DAM HT (FT) / MX.STOR. (AC FT) / PWR. HD. (FT)	EXIST.CAP. (KW) / INC. CAP. (KW) / TOT. CAP. (KW)	EXIST.ENRG (MWH) / INC.ENERGY (MWH) / TOT.ENERGY (MWH)	ANUL. COST (1000 $) / ENERGY COST ($/MWH)	ERC ECONOMIC (SEQUENCE RANK) / ERC NONECONOMIC (SEQUENCE RANK) / ERC COMPOSITE (SEQUENCE RANK)
WIINCS0227	BIG FALLS 2WP917		45 33.3	HR	0	7780	41000	309.90	1953
2	RUSK	FLAMBEAU	90 57.6	OP	5870	7364	7750	39.983	1953
	LAKE SUPERIOR DIST POWER		1838	1760.0	45.0	15144	48750		1953
WIINCS0228	FLAMBEAU 2WP683		45 29.4	HR	0	15000	68000	122.75	1937
2	RUSK	FLAMBEAU	91 2.7	OP	57810	2487	2806	43.735	1937
	DAIRYLAND POWER COOP		1910	1760.0	66.0	17487	70806		1937
WIINCS0226	LADYSMITH		45 27.8	HR	26.0	1800	11000	186.43	1909
2	RUSK	FLAMBEAU	91 5.0	OP	3370	2248	5236	35.605	1909
	LAKE SUPERIOR DIST POWER		1940	1873.0	16.5	4048	16236		1909
WIINCS0300	ARPIN		45 45.5	HR	0	1450	5800	197.79	1946
2	SAWYER	CHIPPEWA	91 12.1	OP	1920	3916	11643	16.987	1946
	NORTH CENTRAL POWER CO		929	825.0	34.0	5366	17443		1946
WICNCS0301	CHIPPEWA		45 53.2	OR	0	0	0	381.49	1914
2	SAWYER	CHIPPEWA	91 4.6	OP	332100	4040	12431	30.687	1914
	NORTHERN STATES POWER CO		864	710.0	25.9	4040	12431		1914

NUMBER OF SITES SATISFYING CONSTRAINTS = 48

COMMAND AND CONSTRAINTS END

SELECTED SITE PERTINENT DATA AND MAPS

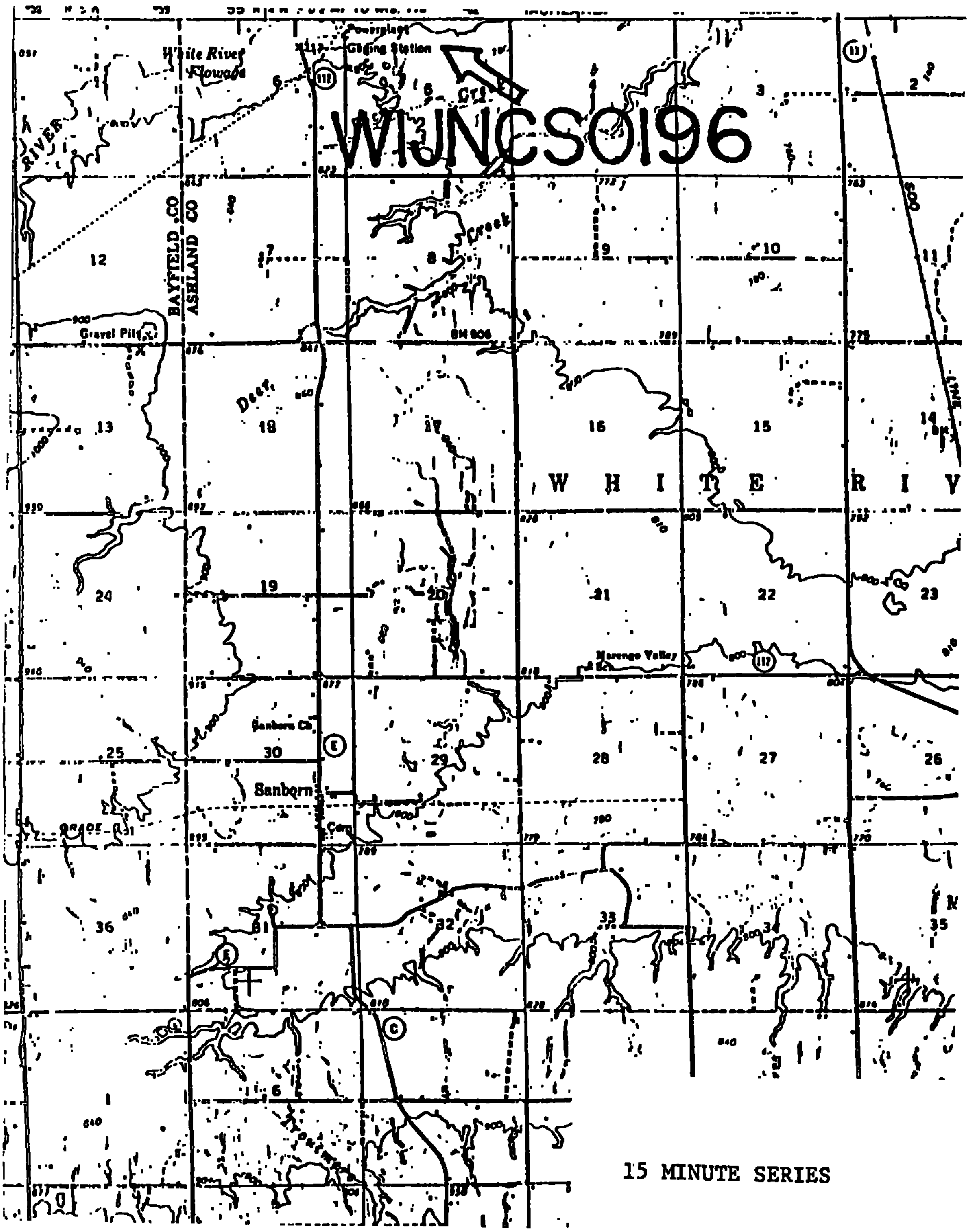
INDEX

PERTINENT DATA

White River 1

ID #WIINCS0196

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Ashland
Stream			White River
Latitude			46° 29.9'
Longitude			90° 54.4'
Owner			Lake Superior District Power
PHYSICAL			
Net Power Head - Ft.			50
Max. Storage - Acre-Ft.			670
Rated Discharge - C.F.S.			1,300
Power	Existing	New Potential	Total
Installed Capacity - KW	1,000	3,800	4,800
Average Annual Energy - MWH	4,900	3,900	8,800
Average Annual Plant Factor - %	56	----	21
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	45.02	----
Average Annual Cost - $	----	173,800	----
Average Annual Benefits - $	----	268,100	----
Net Benefits - $	----	94,300	----
B/C	----	1.54	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

0 1 2 3 4 MILES

PERTINENT DATA

Chippewa Falls

ID # WIINGS0212

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Chippewa
Stream			Chippewa
Latitude			44° 55.8'
Longitude			91° 23.2'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			30
Max. Storage - Acre-Ft.			4,800
Rated Discharge - C.F.S.			12,000
Power	Existing	New Potential	Total
Installed Capacity - KW	21,600	2,300	23,900
Average Annual Energy - MWH	73,400	9,300	82,800
Average Annual Plant Factor - %	39	----	40
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	13.65	----
Average Annual Cost - $	----	126,800	----
Average Annual Benefits - $	----	278,100	----
Net Benefits - $	----	151,300	----
B/C	----	2.19	----

SCALE 1:24 000

PERTINENT DATA

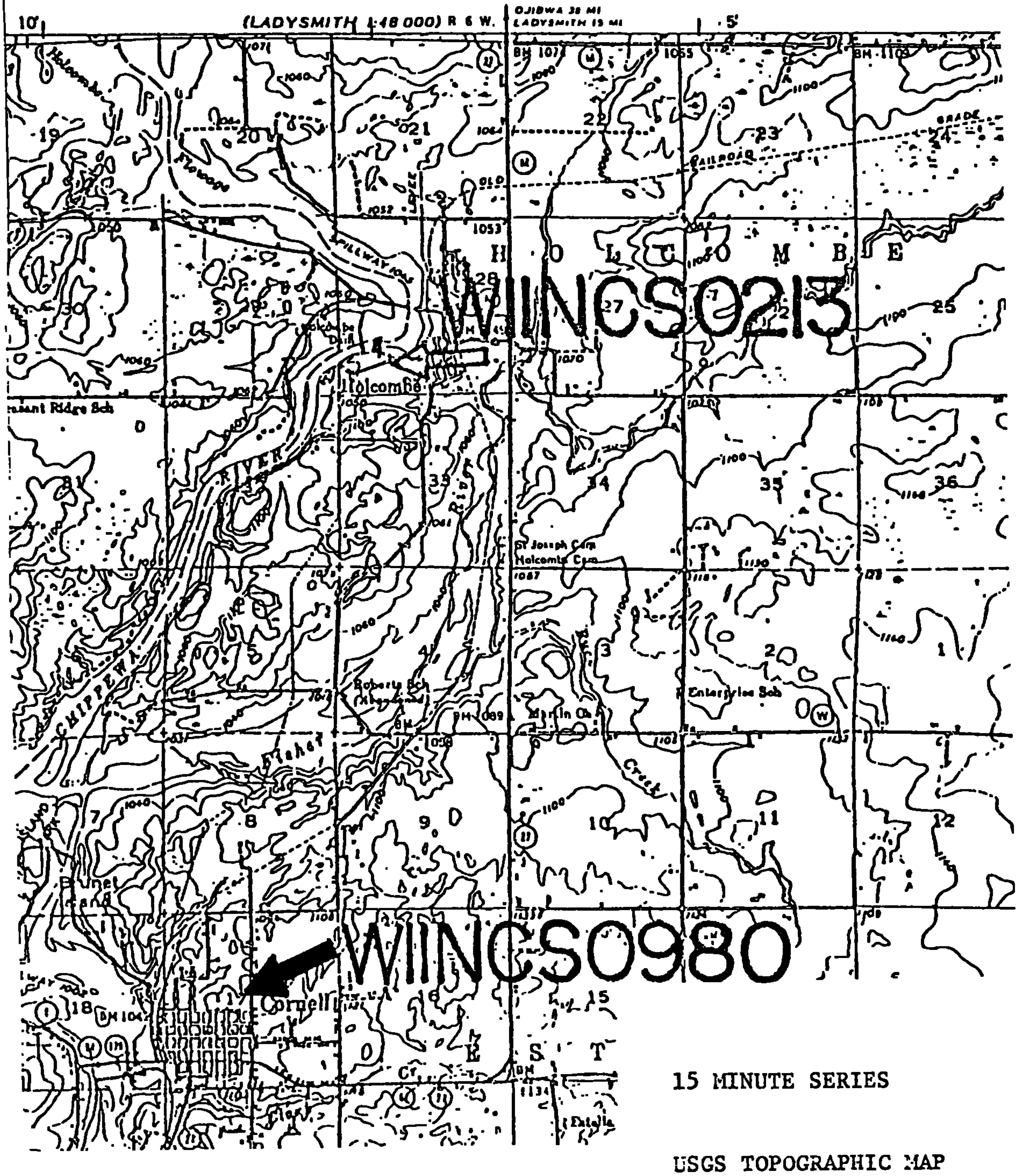
Cornell 19

ID #WIINCS0980

ITEM				DESCRIPTION
Location				
State				Wisconsin
County				Chippewa
Stream				Chippewa
Latitude				45° 09.8'
Longitude				91° 09.5'
Owner				Northern States Power Co.
PHYSICAL				
Net Power Head - Ft.				38
Max. Storage - Acre-Ft.				22,300
Rated Discharge - C.F.S.				13,800

Power	Existing	New Potential	Total
Installed Capacity - KW	30,900	7,400	38,300
Average Annual Energy - MWH	87,000	12,200	99,200
Average Annual Plant Factor - %	32	----	30
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	36.41	----
Average Annual Cost - $	----	445,400	----
Average Annual Benefits - $	----	588,200	----
Net Benefits - $	----	142,800	----
B/C	----	1.32	----

STATE OF WISCONSIN



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

0 1 2 3 4 MILES

PERTINENT DATA

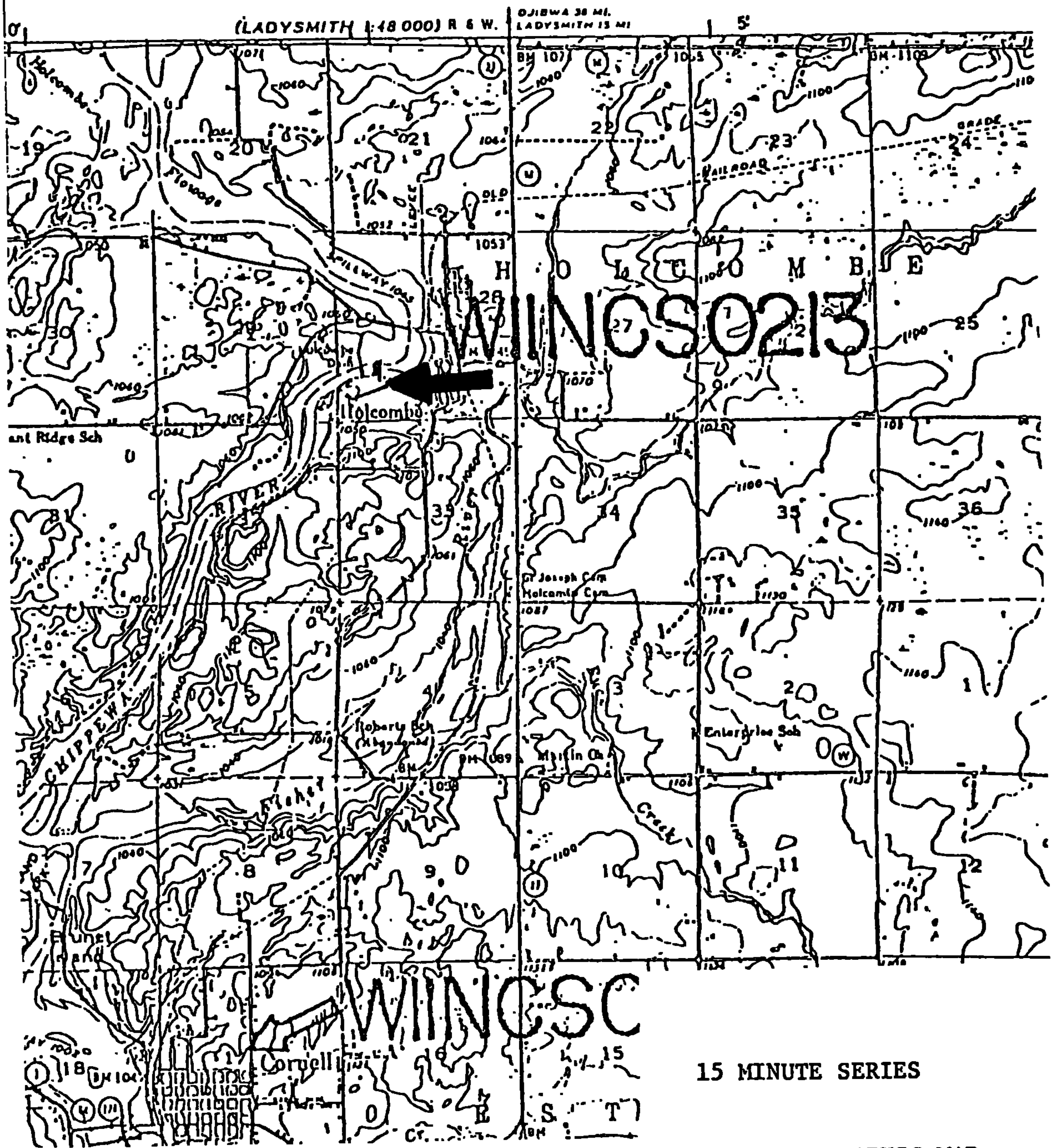
Holcombe II

ID # W11NCS0213

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Chippewa
Stream			Chippewa
Latitude			45° 13.4'
Longitude			91° 7.7'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			45
Max. Storage - Acre-Ft.			72,000
Rated Discharge - C.F.S.			12,000

Power	Existing	New Potential	Total
Installed Capacity - KW	33,800	5,300	39,100
Average Annual Energy - MWH	99,800	14,800	114,600
Average Annual Plant Factor - %	34	----	33
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	19.94	----
Average Annual Cost - $	----	296,000	----
Average Annual Benefits - $	----	520,200	----
Net Benefits - $	----	224,200	----
B/C	----	1.76	----

STATE OF WISCONSIN



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

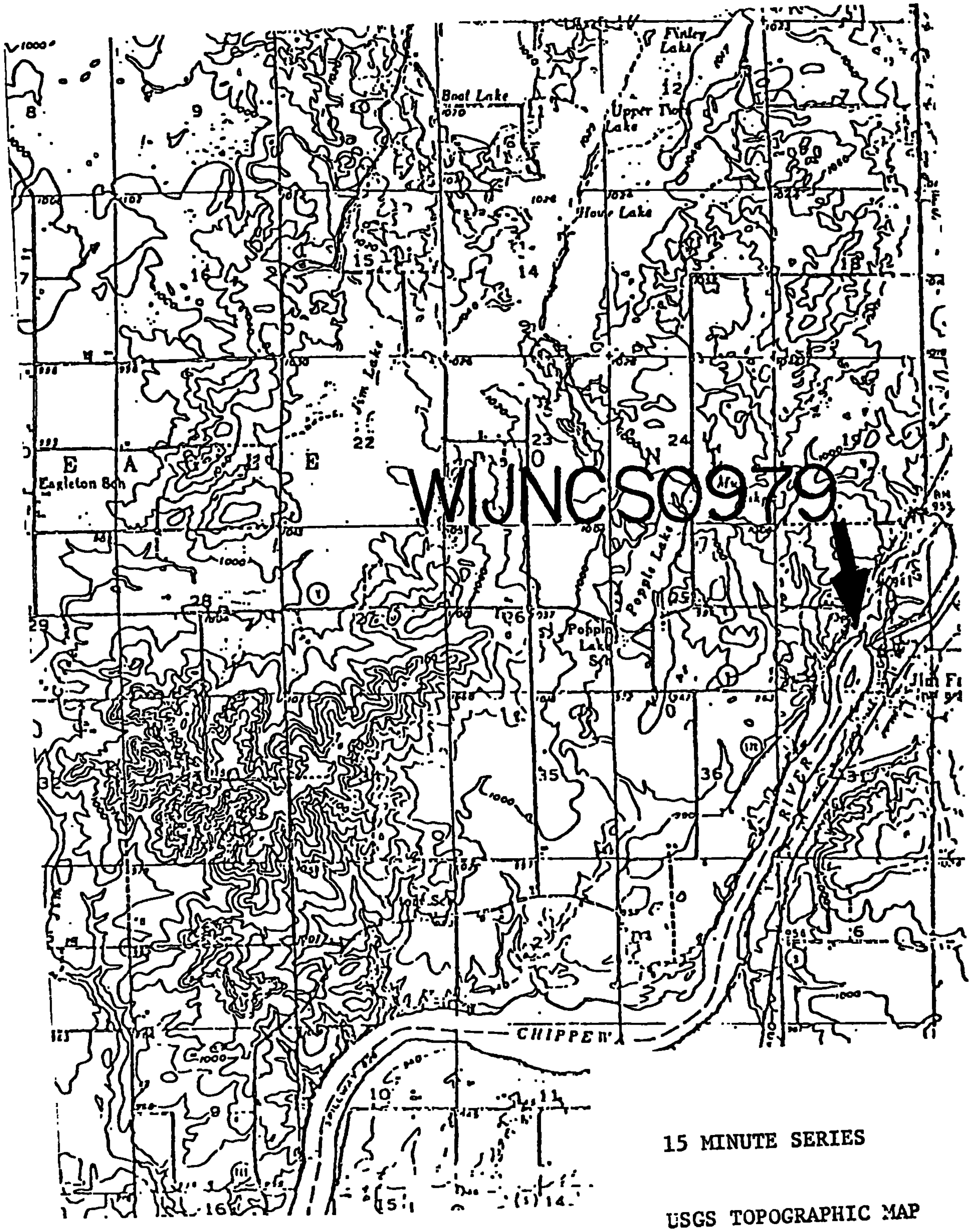
0 1 2 3 4 MILES

PERTINENT DATA

Jim Falls

ID #WIJNCS0979

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Chippewa
Stream			Chippewa
Latitude			45° 3.5'
Longitude			91° 16.0'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			54
Max. Storage - Acre-Ft.			21,500
Rated Discharge - C.F.S.			14,600
Power	Existing	New Potential	Total
Installed Capacity - KW	14,400	43,300	57,700
Average Annual Energy - MWH	82,800	60,200	143,000
Average Annual Plant Factor - %	66	----	28
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	33.68	----
Average Annual Cost - $	----	2,029,400	----
Average Annual Benefits - $	----	3,442,200	----
Net Benefits - $	----	1,412,800	----
B/C	----	1.69	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

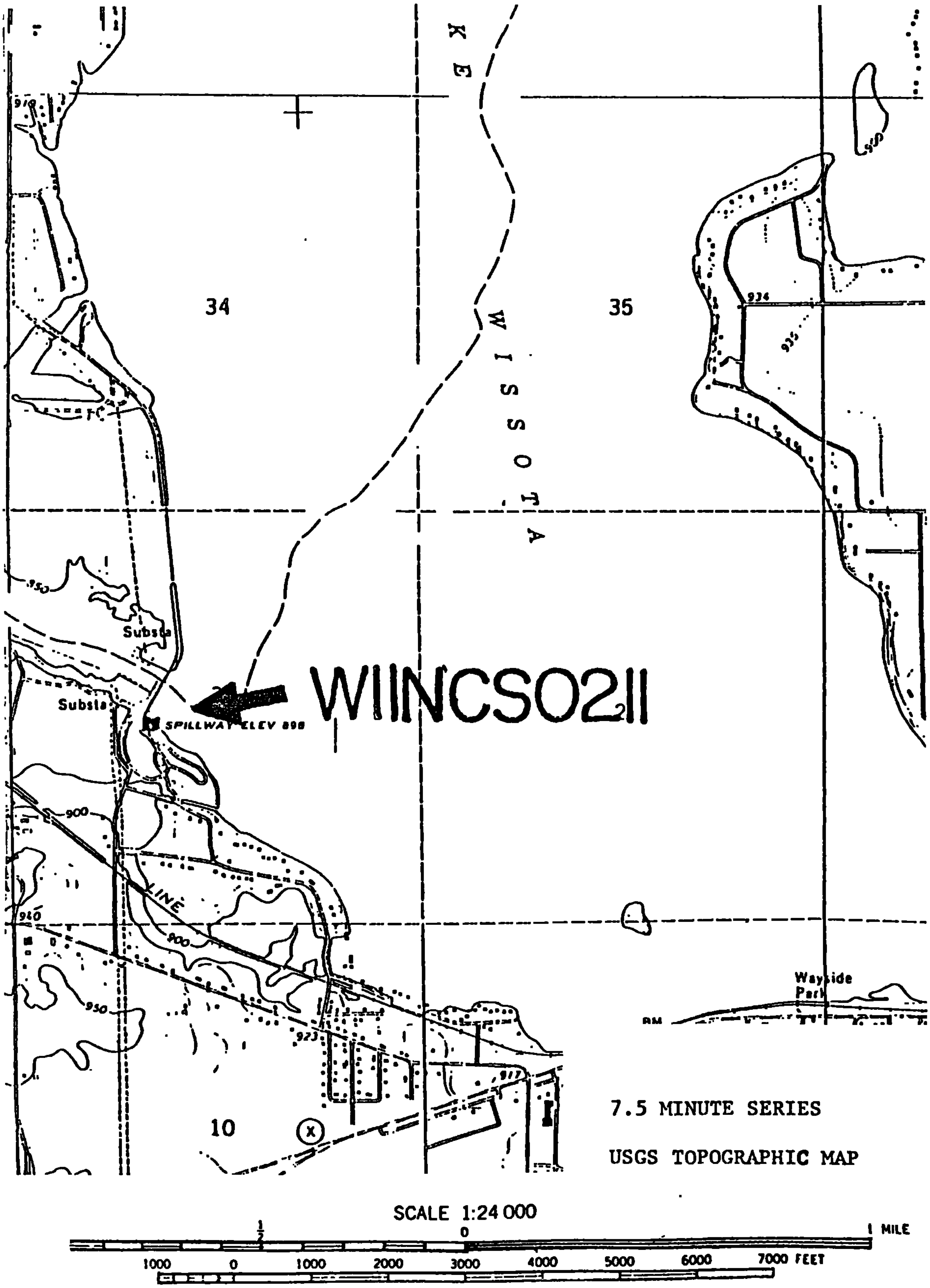
0 1 2 3 4 MILES

PERTINENT DATA

Wissota WP

ID # W11NCS0211

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Chippewa
Stream			Chippewa
Latitude			44° 56.2'
Longitude			91° 20.4'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			57
Max. Storage - Acre-Ft.			226,000
Rated Discharge - C.F.S.			15,800
Power	Existing	New Potential	Total
Installed Capacity - KW	35,300	30,400	65,700
Average Annual Energy - MWH	141,600	28,300	169,900
Average Annual Plant Factor - %	46	----	30
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	50.35	----
Average Annual Cost - $	----	1,423,300	----
Average Annual Benefits - $	----	2,069,900	----
Net Benefits - $	----	646,600	----
B/C	----	1.45	----

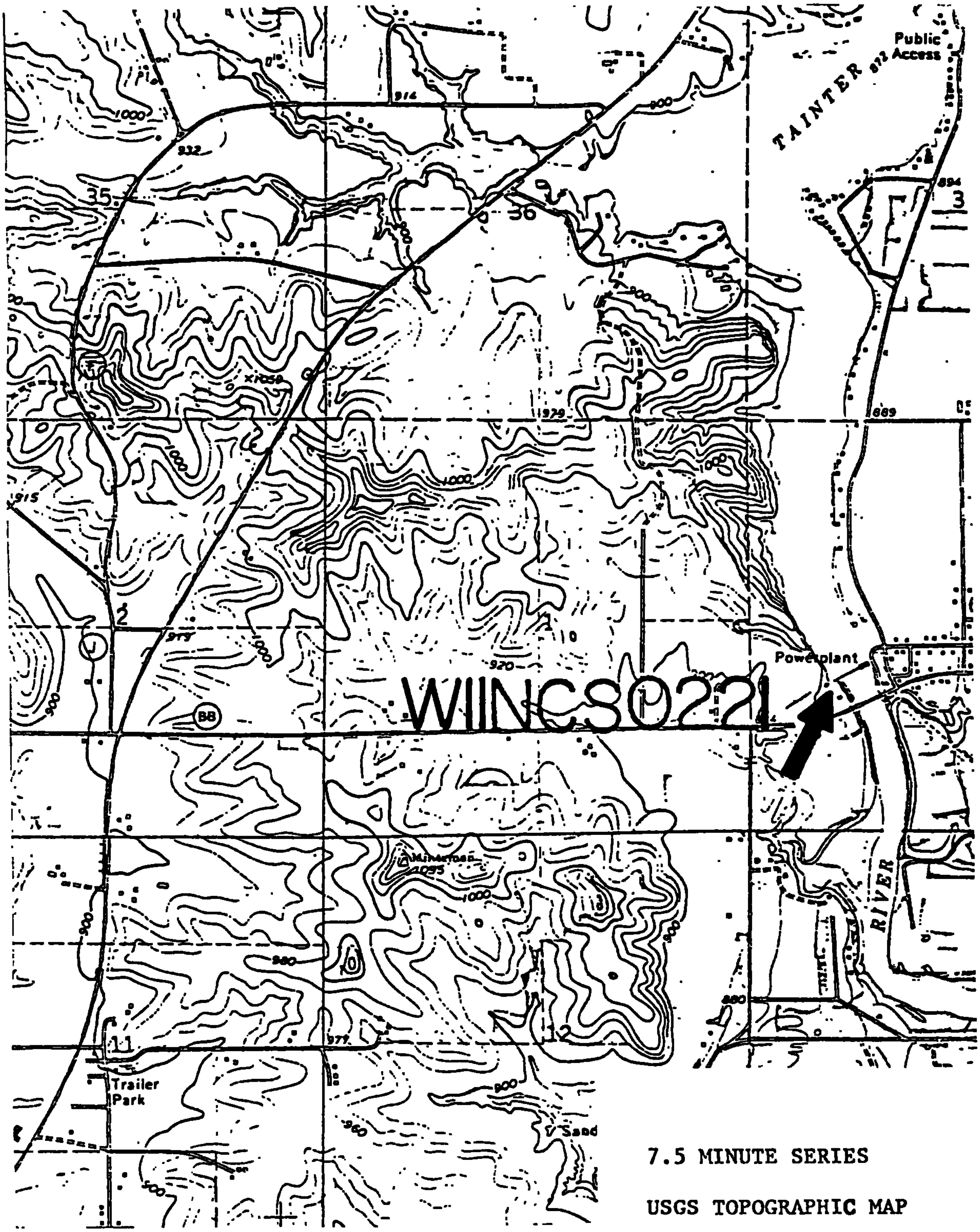

KE
WISSOTA
34
35
Substa
Substa
SPILLWAY ELEV 898
WIINCS0211
LINE
900
950
10
Wayside Park
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Cedar Falls

ID #WIINCS0221

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Dunn
Stream			Red Cedar
Latitude			44° 52.6'
Longitude			91° 55.8'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			49
Max. Storage - Acre-Ft.			12,000
Rated Discharge - C.F.S.			4,800
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	6,000	9,000	15,000
Average Annual Energy - MWH	29,100	2,300	31,400
Average Annual Plant Factor - %	55	----	24
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	193.38	----
Average Annual Cost - $	----	440,700	----
Average Annual Benefits - $	----	541,700	----
Net Benefits - $	----	101,000	----
B/C	----	1.23	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1 MILE

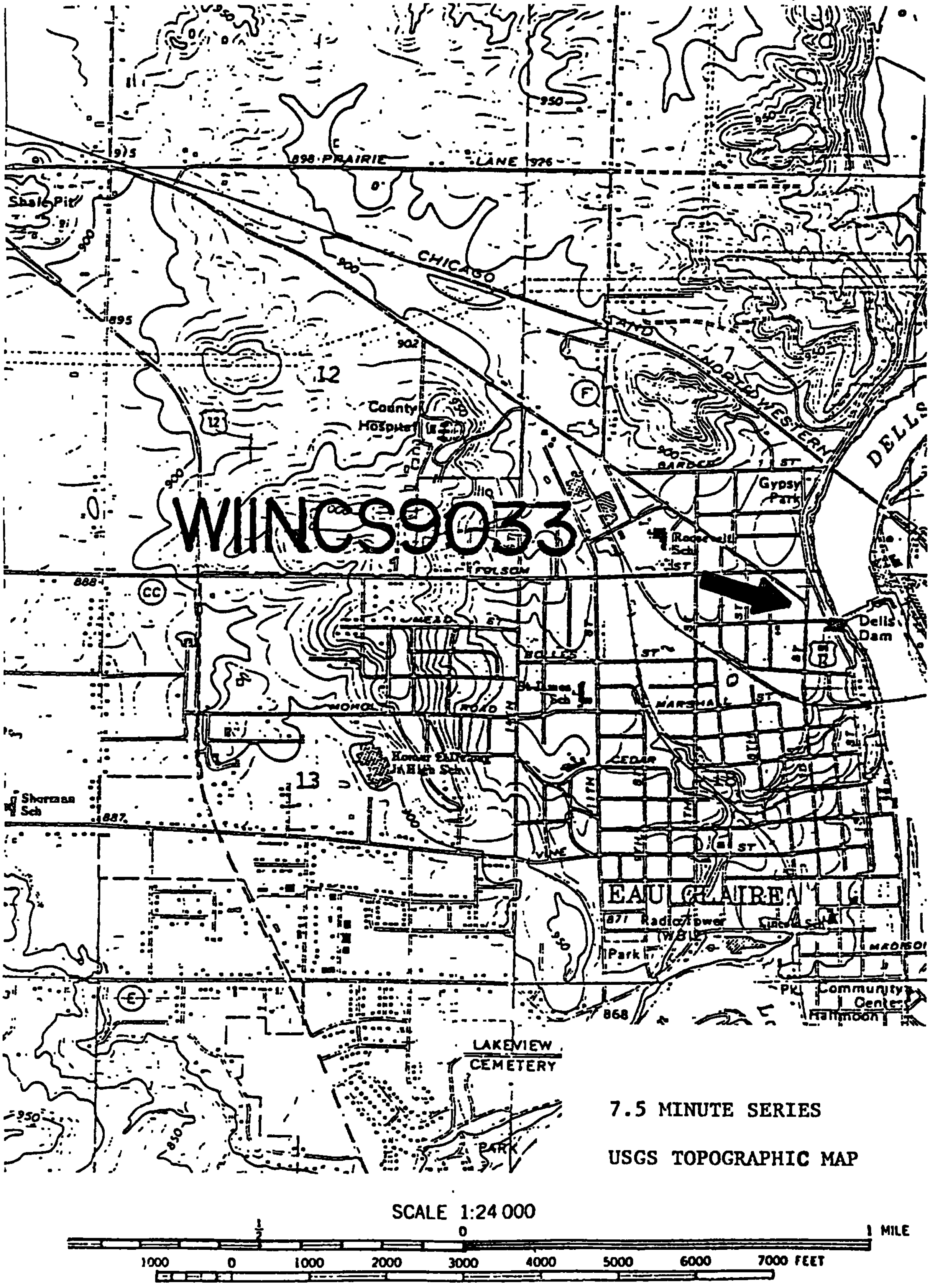
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Dells 1907

ID # WIJNCS9033

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Eau Claire
Stream			Chippewa
Latitude			44° 49.5'
Longitude			91° 30.7'
Owner			City of Eau Claire
PHYSICAL			
Net Power Head - Ft.			27
Max. Storage - Acre-Ft.			12,000
Rated Discharge - C.F.S.			12,500
Power	Existing	New Potential	Total
Installed Capacity - KW	8,400	16,300	24,700
Average Annual Energy - MWH	43,800	34,400	74,200
Average Annual Plant Factor - %	60	----	36
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	28.71	----
Average Annual Cost - $	----	987,300	----
Average Annual Benefits - $	----	1,478,200	----
Net Benefits - $	----	490,900	----
B/C	----	1.50	----



WINCS9033
PRAIRIE
LANE
CHICAGO
AND
NORTHWESTERN
Shale Pit
County Hospital
Gypsy Park
Roosevelt Sch
FOLSOM
GARDEN ST
MARSHALL ST
CEDAR
VINE
DELLS
Dells Dam
EAU CLAIRE
Radio Tower
Park
Community Center
Sherman Sch
LAKEVIEW CEMETERY
PARK
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

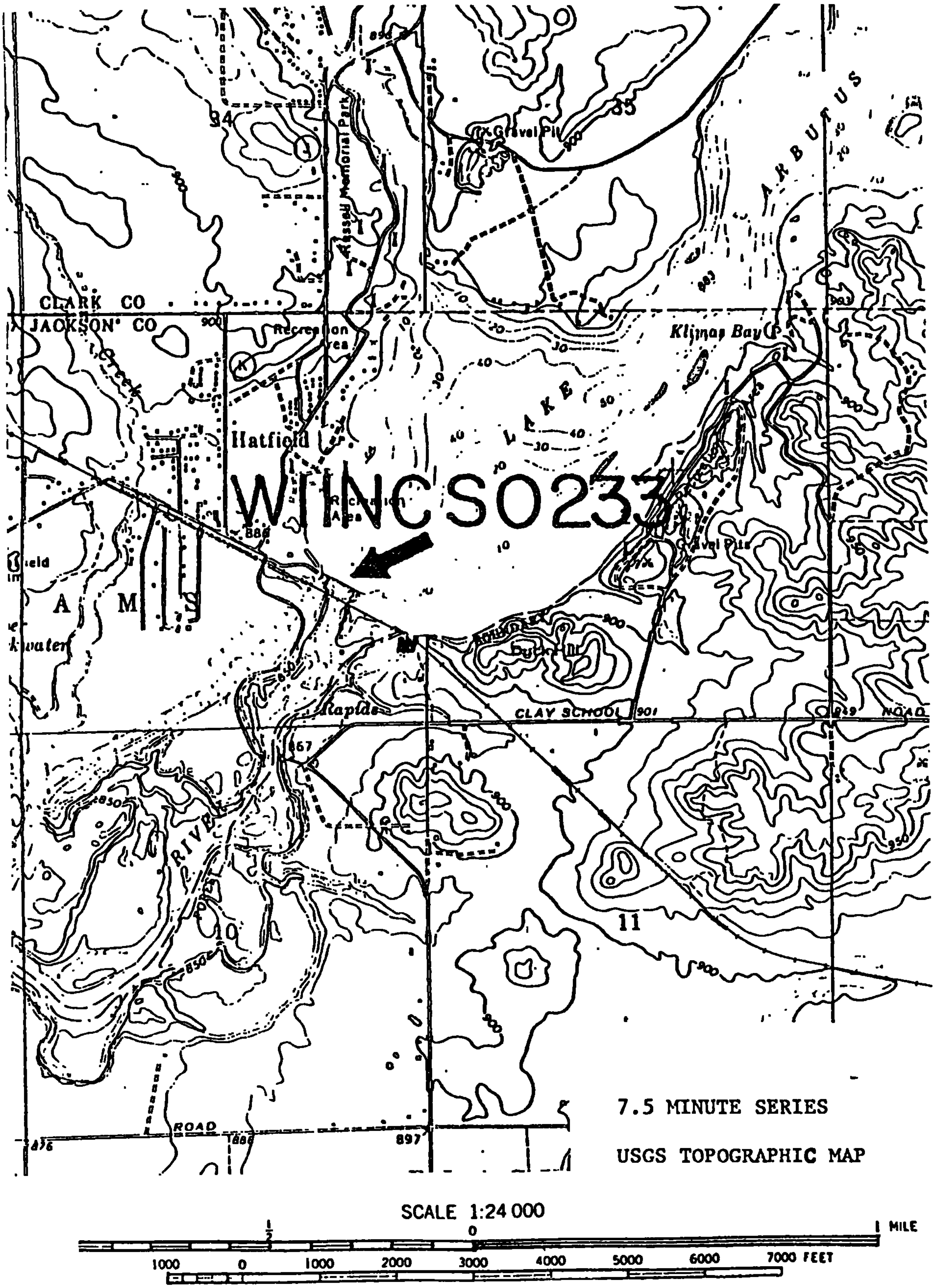
PERTINENT DATA

Hatfield

ID # WIINCS0233

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Jackson
Stream			Black
Latitude			44° 24.6'
Longitude			90° 43.3'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			90
Max. Storage - Acre-Ft.			23,400
Rated Discharge - C.F.S.			2,500

Power	Existing	New Potential	Total
Installed Capacity - KW	3,840	12,500	16,340
Average Annual Energy - MWH	16,000	19,900	35,900
Average Annual Plant Factor - %	48	----	25
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	39.31	----
Average Annual Cost - $	----	780,300	----
Average Annual Benefits - $	----	1,034,500	----
Net Benefits - $	----	254,200	----
B/C	----	1.33	----

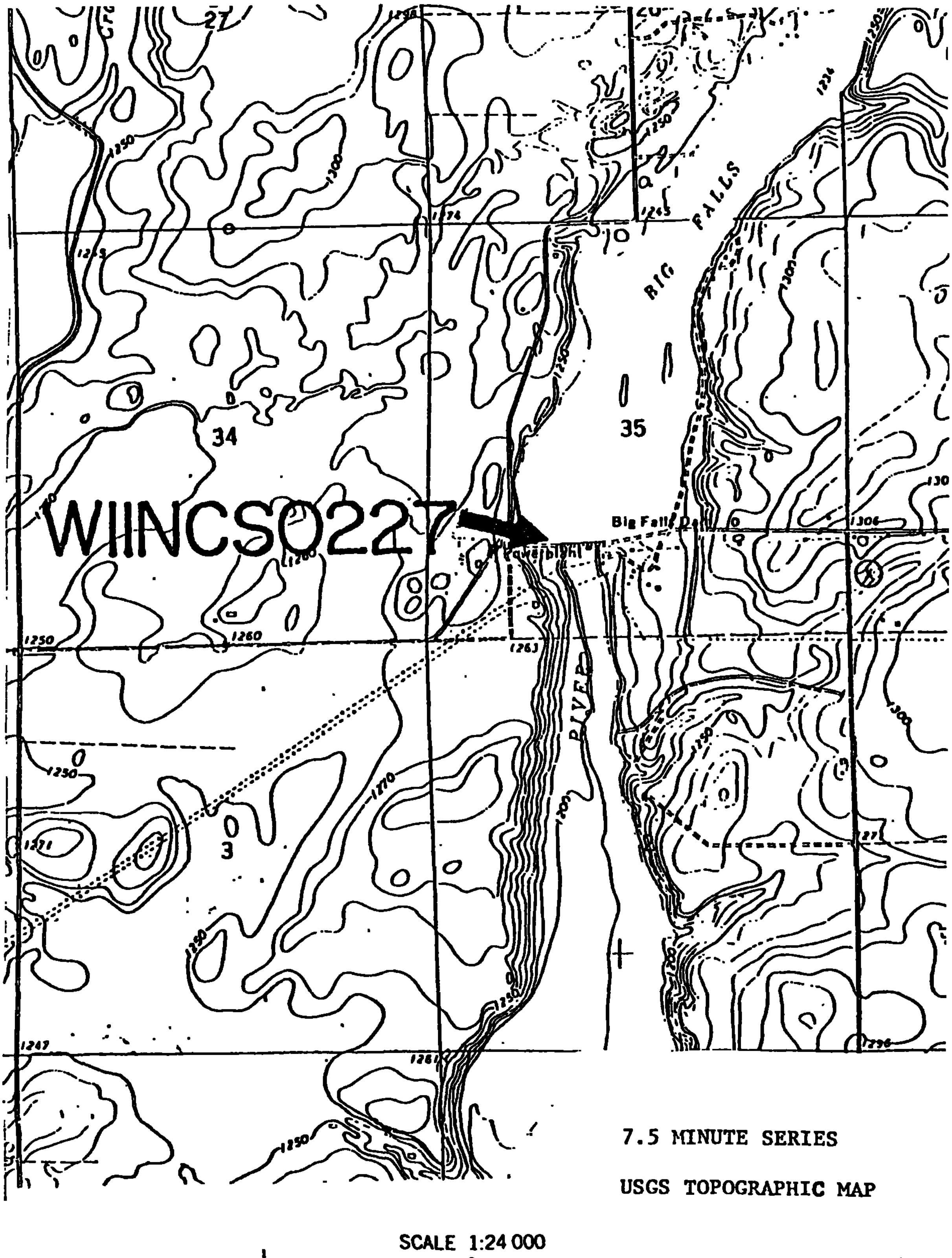

WINCS0233
CLARK CO
JACKSON CO
Hatfield
Recreation Area
Russell Memorial Park
Gravel Pit
Gravel Pits
LAKE ARBUTUS
Klimas Bay
CLAY SCHOOL ROAD
Rapids
RIVER
ROAD
34
35
10
11
897
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
7000 FEET

PERTINENT DATA

Big Falls

ID # WIINCS0227

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Rusk
Stream			Flambeau
Latitude			45° 33.3'
Longitude			90° 57.6'
Owner			Lake Superior Dist Power
PHYSICAL			
Net Power Head - Ft.			45
Max. Storage - Acre-Ft.			5,900
Rated Discharge - C.F.S.			4,600
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	7,800	7,400	15,200
Average Annual Energy - MWH	41,000	7,800	48,800
Average Annual Plant Factor - %	60	----	37
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	39.98	----
Average Annual Cost - $	----	309,900	----
Average Annual Benefits - $	----	568,700	----
Net Benefits - $	----	258,800	----
B/C	----	1.84	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1/2 0 1 MILE

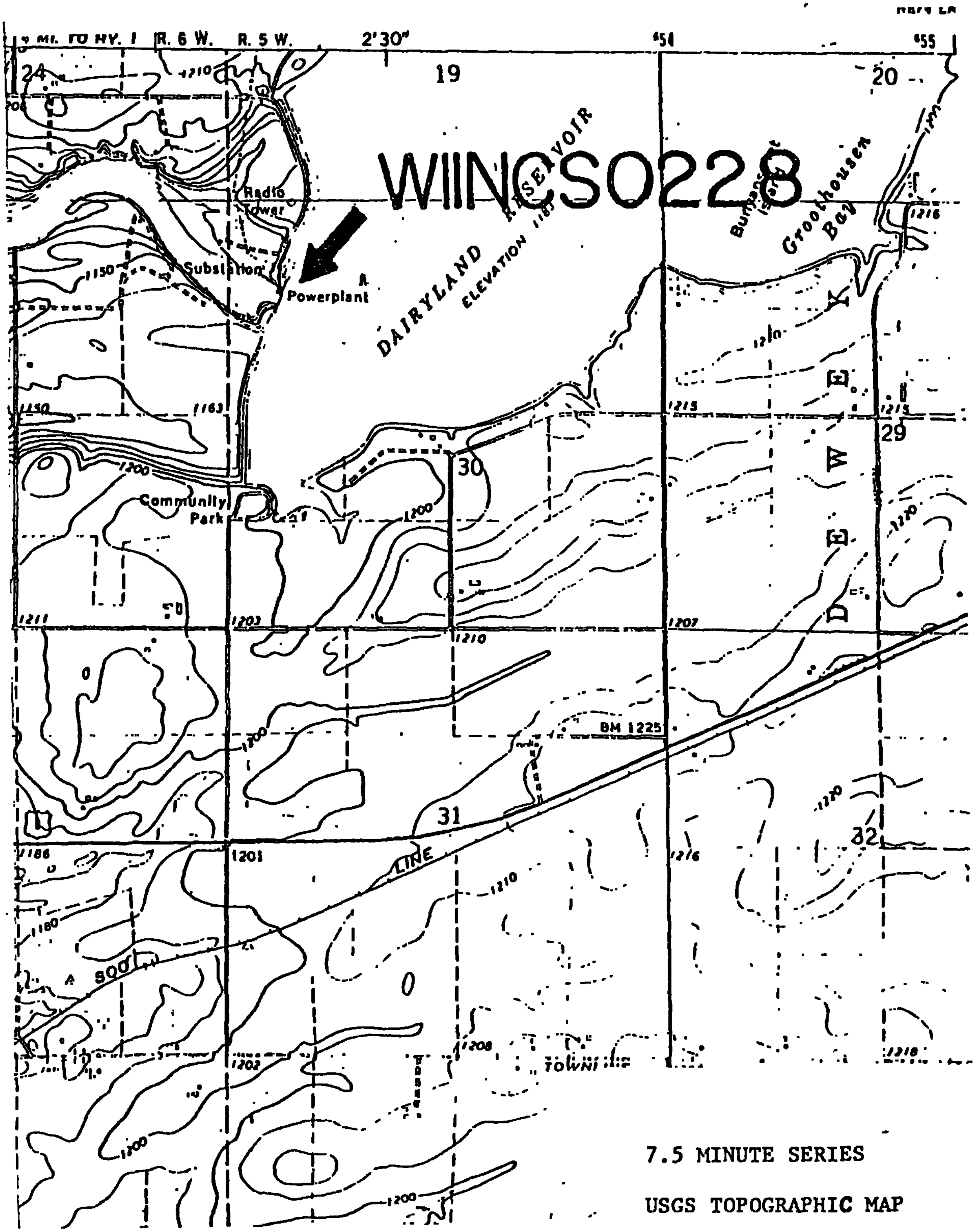
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Flambeau 2

ID # W11NCS0228

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Rusk
Stream			Flambeau
Latitude			45 o 29.4'
Longitude			91 o 2.7'
Owner			Dairyland Power Coop.
PHYSICAL			
Net Power Head - Ft.			66
Max. Storage - Acre-Ft.			57,800
Rated Discharge - C.F.S.			3,600
Power	Existing	New Potential	Total
Installed Capacity - KW	15,000	2,500	17,500
Average Annual Energy - MWH	68,000	2,800	70,800
Average Annual Plant Factor - %	52	----	46
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	43.74	----
Average Annual Cost - $	----	122,800	----
Average Annual Benefits - $	----	286,600	----
Net Benefits - $	----	113,800	----
B/C	----	1.93	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1 MILE

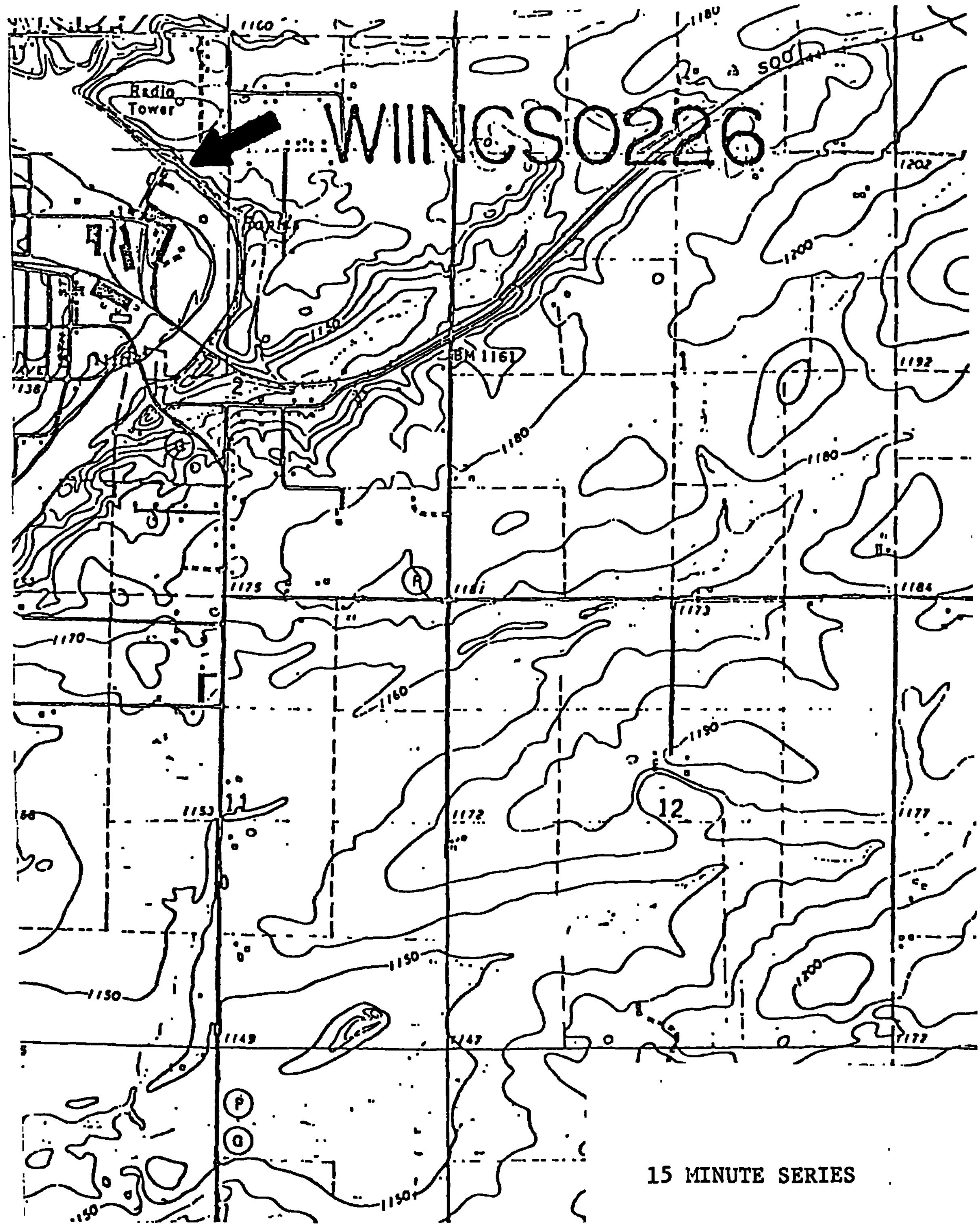
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Ladysmith

ID # W11NCS0226

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Rusk
Stream			Flambeau
Latitude			45 o 27.8'
Longitude			91 o 5.0'
Owner			Lake Superior District Power
PHYSICAL			
Net Power Head - Ft.			16
Max. Storage - Acre-Ft.			3,400
Rated Discharge - C.F.S.			3,400
Power	Existing	New Potential	Total
Installed Capacity - KW	1,800	2,200	4,000
Average Annual Energy - MWH	11,000	5.200	16,200
Average Annual Plant Factor - %	70	----	46
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	35.61	----
Average Annual Cost - $	----	186,400	----
Average Annual Benefits - $	----	219,000	----
Net Benefits - $	----	32,600	----
B/C	----	1.17	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

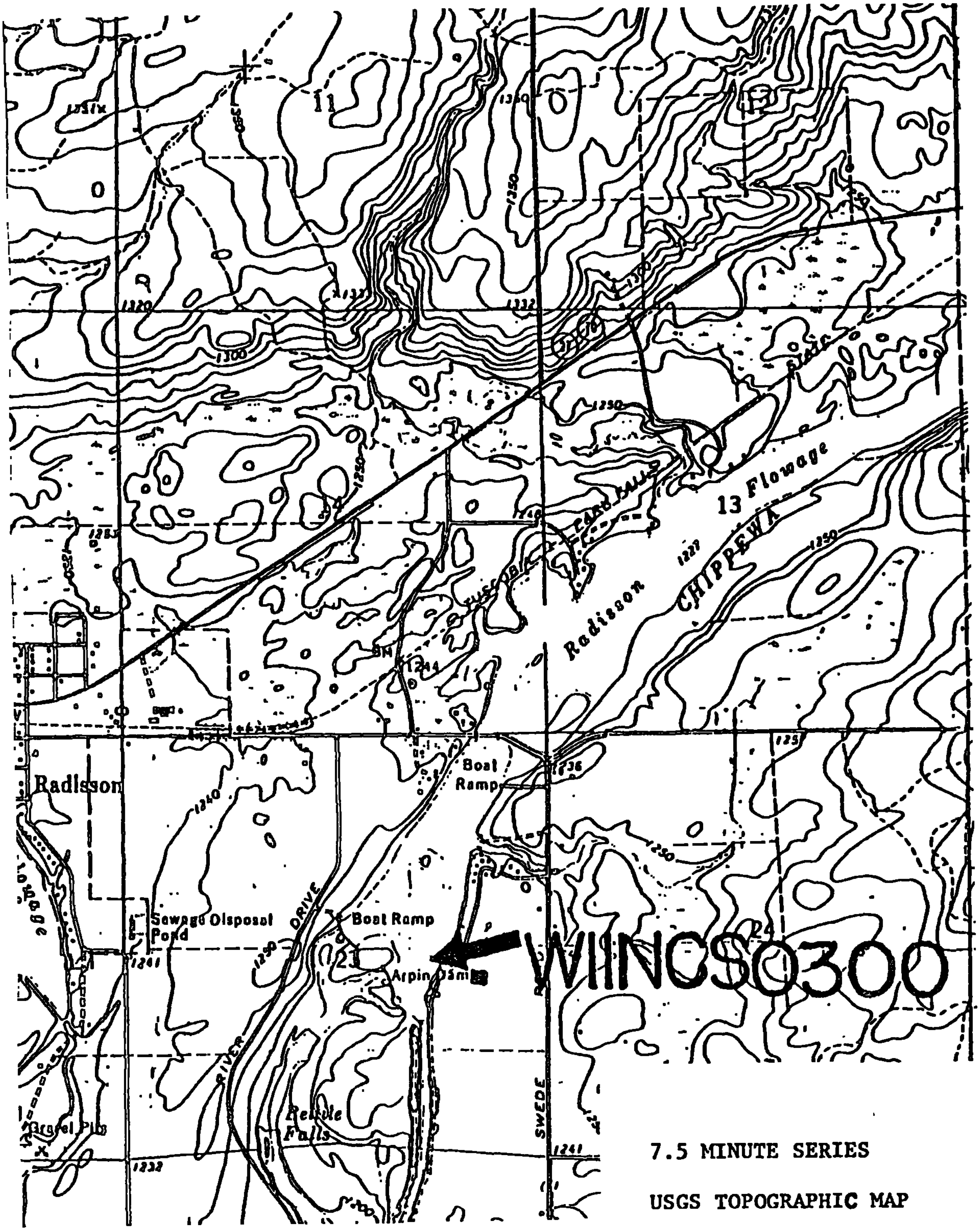
0 1 2 3 4 MILES

PERTINENT DATA

Arpin

ID # W11NCS0300

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Sawyer
Stream			Chippewa
Latitude			45° 45.5'
Longitude			91° 12.1'
Owner			North Central Power Co.
PHYSICAL			
Net Power Head - Ft.			34
Max. Storage - Acre-Ft.			1,900
Rated Discharge - C.F.S.			2,200
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	1,450	3,900	5,350
Average Annual Energy - MWH	5,800	11,600	17,400
Average Annual Plant Factor - %	46	----	37
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	16.99	----
Average Annual Cost - $	----	197,800	----
Average Annual Benefits - $	----	395,400	----
Net Benefits - $	----	197,600	----
B/C	----	2.00	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1/2 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

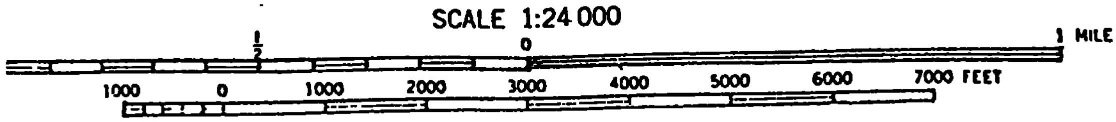
Chippewa

ID # WICNCS0301

ITEM			DESCRIPTION
Location			
State			Wisconsin
County			Sawyer
Stream			Chippewa
Latitude			45° 53.2'
Longitude			91° 4.6'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			26
Max. Storage - Acre-Ft.			332,100
Rated Discharge - C.F.S.			2,100
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	0	4,000	4,000
Average Annual Energy - MWH	0	12,400	12,400
Average Annual Plant Factor - %	0	----	35
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	30.69	----
Average Annual Cost - $	----	381,500	----
Average Annual Benefits - $	----	430,700	----
Net Benefits - $	----	49,200	----
B/C	----	1.13	----

7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

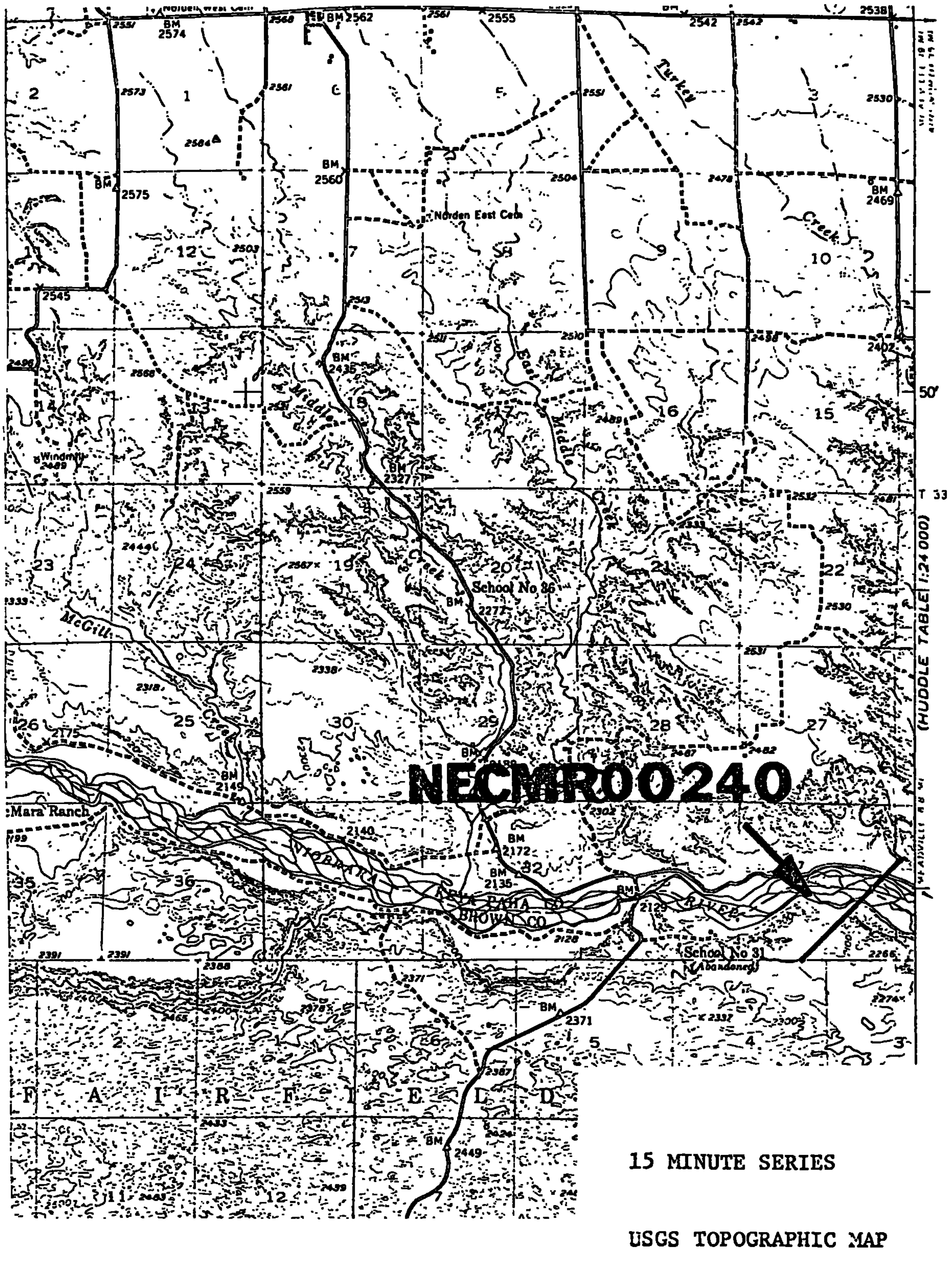


PERTINENT DATA

Norden Dam

ID # NECMR00240

ITEM			DESCRIPTION
Location			
State			Nebraska
County			Brown
Stream			Niobrara Rive:
Latitude			42° 28.2'
Longitude			100° 0.0'
Owner			Water Power Resources Service
PHYSICAL			
Net Power Head - Ft.			175
Max. Storage - Acre-Ft.			411.000
Rated Discharge - C.F.S.			1,775
Power	Existing	New Potential	Total
Installed Capacity - KW	0	22,000	22,000
Average Annual Energy - MWH	0	70,100	70,100
Average Annual Plant Factor - %	0	----	36
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	15.56	----
Average Annual Cost - $	----	1,091,300	----
Average Annual Benefits - $	----	2,670,800	----
Net Benefits - $	----	1,579,500	----
B/C	----	2.45	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

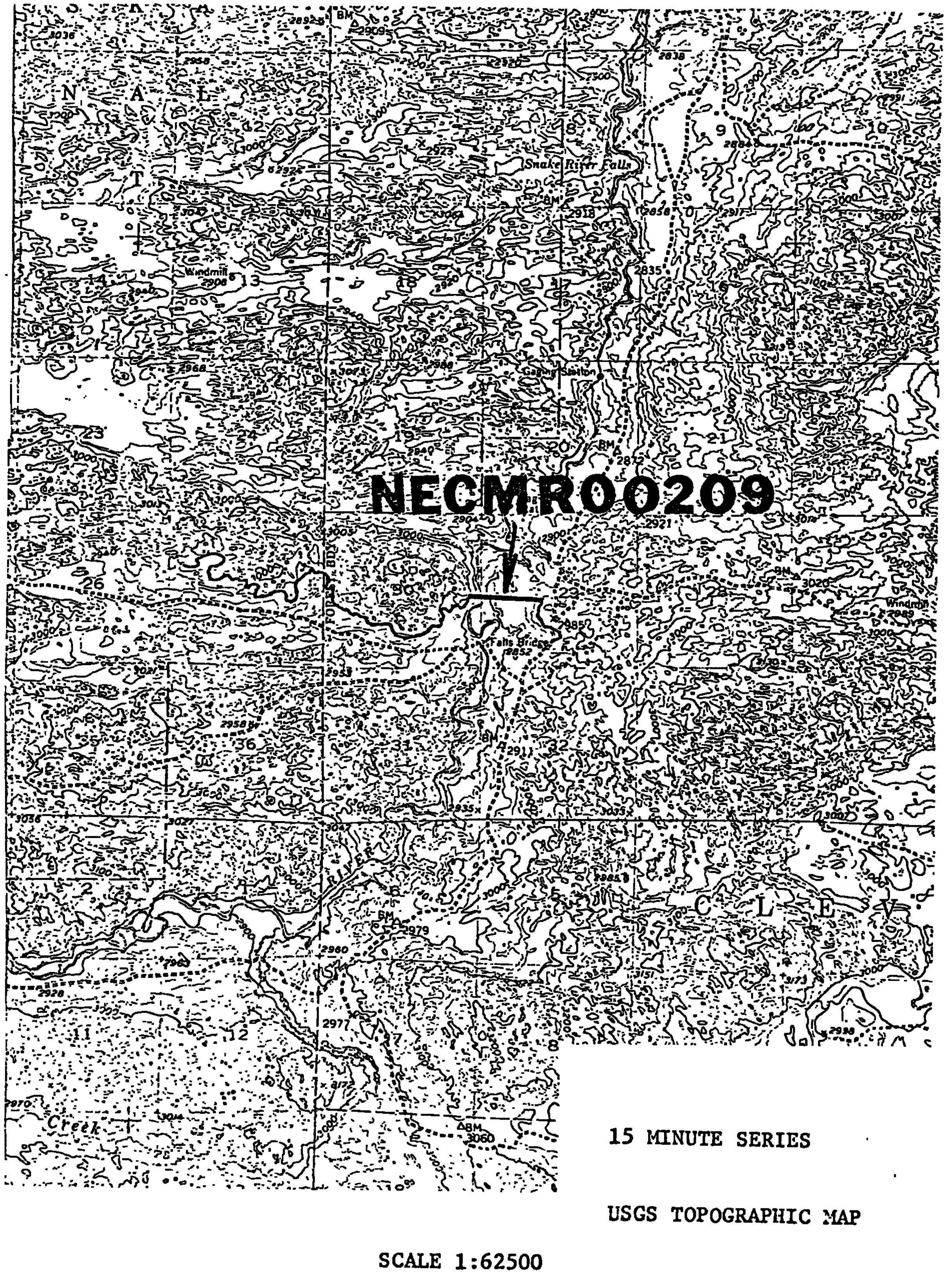
0 1 2 3 4 MILES

PERTINENT DATA

Merritt Reservoir

ID # NECMRO0209

ITEM			DESCRIPTION
Location			
State			Nebraska
County			Cherry
Stream			Snake River
Latitude			42° 38.0'
Longitude			100° 52.3'
Owner			Water Power Resources Service
PHYSICAL			
Net Power Head - Ft.			110
Max. Storage - Acre-Ft.			86,100
Rated Discharge - C.F.S.			260
Power	Existing	New Potential	Total
Installed Capacity - KW	0	2,000	2,000
Average Annual Energy - MWH	0	12,400	12,400
Average Annual Plant Factor - %	0	----	71
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	19.17	----
Average Annual Cost - $	----	237,400	----
Average Annual Benefits - $	----	287,000	----
Net Benefits - $	----	49,600	----
B/C	----	1.21	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

0 1 2 3 4 MILES

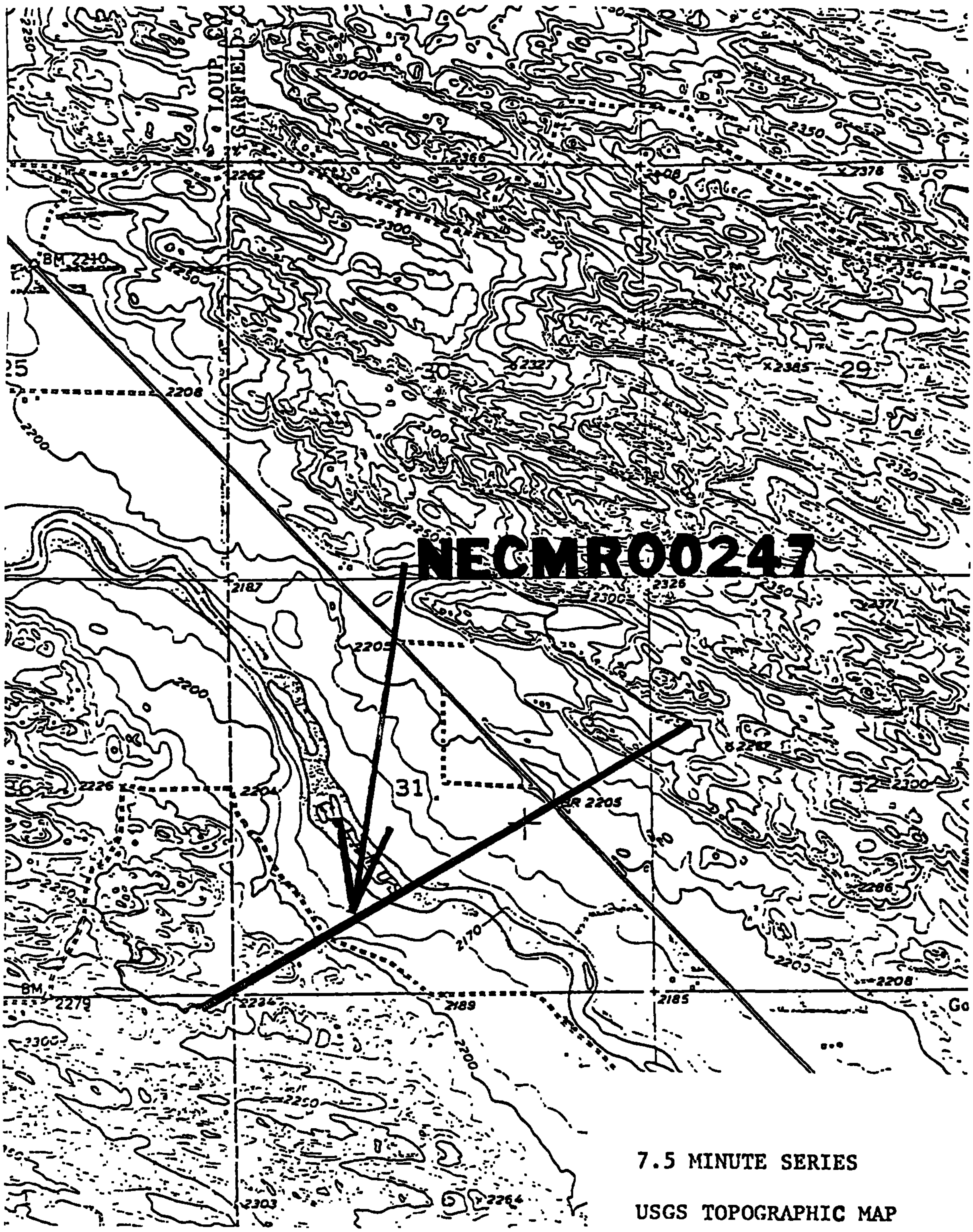
PERTINENT DATA

Calamus

ID # NECMR00247

ITEM				DESCRIPTION
Location				
State				Nebraska
County				Garfield
Stream				Calamus River
Latitude				41° 49.9'
Longitude				99° 12.4'
Owner				Water Power Resources Service
PHYSICAL				
Net Power Head - Ft.				80
Max. Storage - Acre-Ft.				128,200
Rated Discharge - C.F.S.				303

Power	Existing	New Potential	Total
Installed Capacity - KW	0	1,700	1,700
Average Annual Energy - MWH	0	11,100	11,100
Average Annual Plant Factor - %	0	----	75
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	19.82	----
Average Annual Cost - $	----	220,000	----
Average Annual Benefits - $	----	329,200	----
Net Benefits - $	----	109,200	----
B/C	----	1.5	----



SCALE 1:24 000

1/2 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

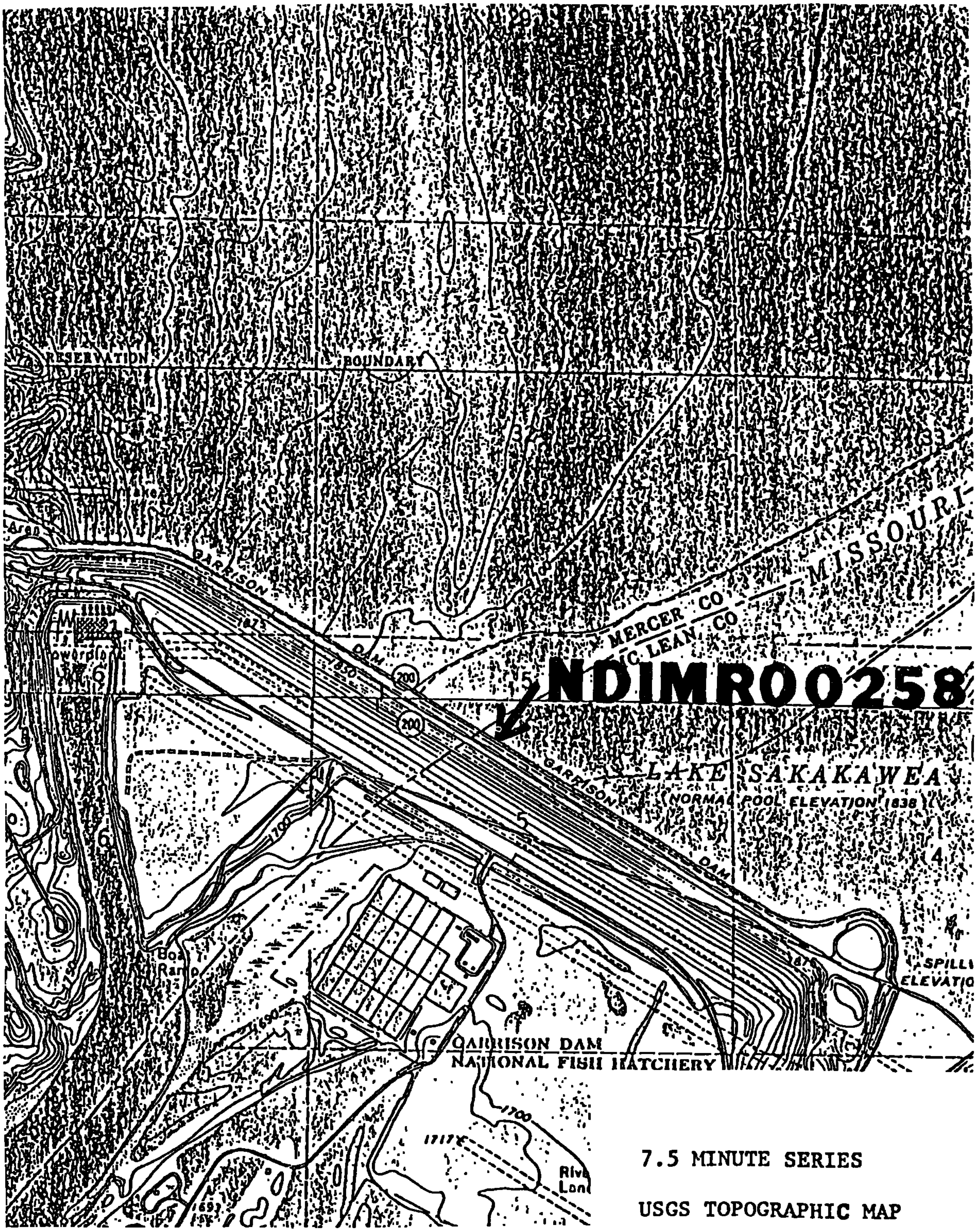
PERTINENT DATA

Lake Sakakawea

ID # NDIMR00258

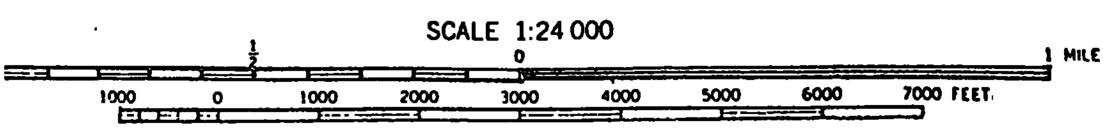
ITEM			DESCRIPTION
Location			
State			North Dakota
County			McLean
Stream			Missouri River
Latitude			47° 30.1'
Longitude			101° 25.9'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			189
Max. Storage - Acre-Ft.			24,200,000
Rated Discharge - C.F.S.			70,300

Power	Existing	New Potential	Total
Installed Capacity - KW	400,000	272,000	672,000
Average Annual Energy - MWH	2,270,000	-66,300	2,203,700
Average Annual Plant Factor - %	64	----	37
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	-	----
Average Annual Cost - $	----	6,070,000	----
Average Annual Benefits - $	----	9,604,000	----
Net Benefits - $	----	3,334,000	----
B/C	----	1.6	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP



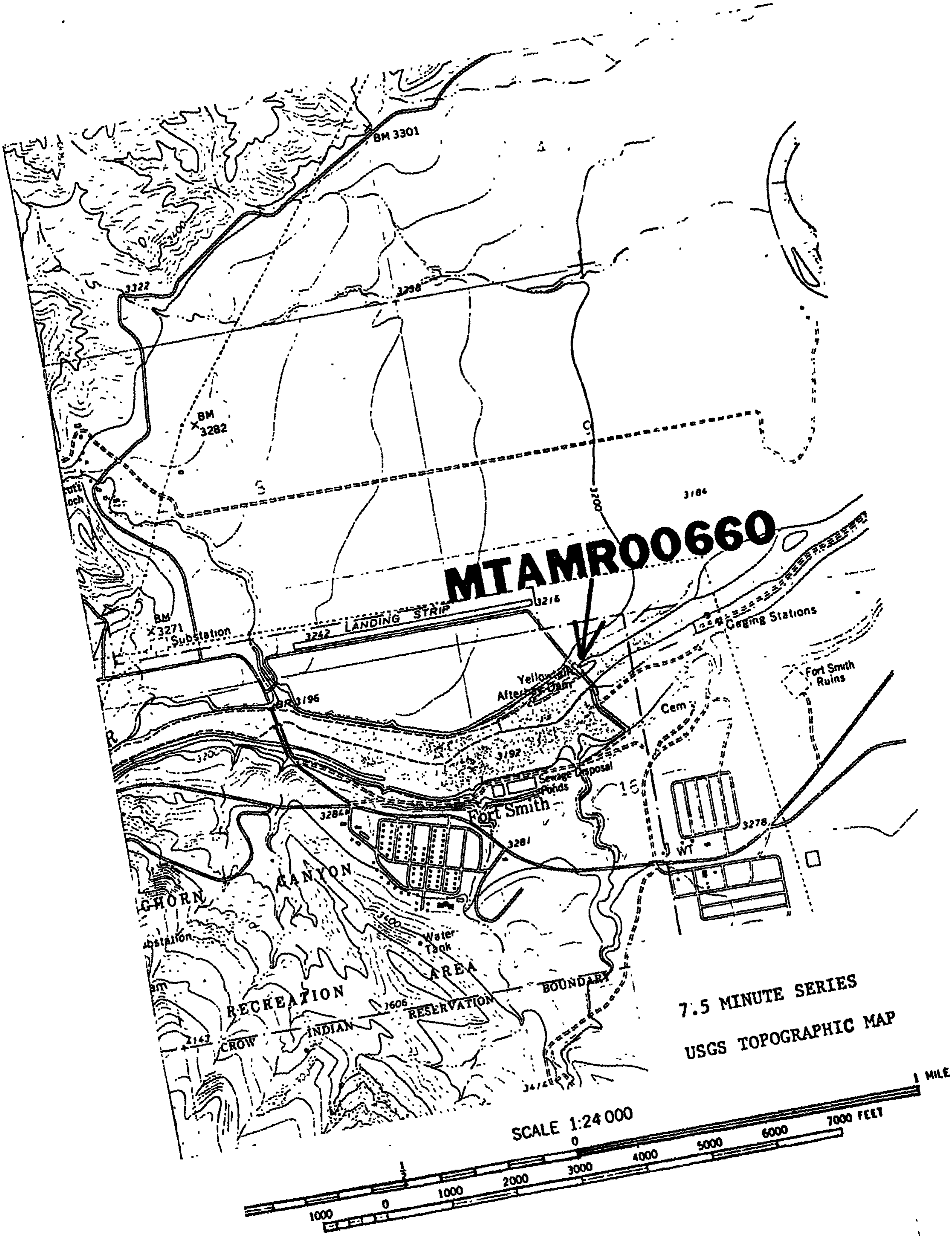
PERTINENT DATA

Yellowtail Afterbay

ID # MTAMR00660

ITEM				DESCRIPTION
Location				
State				Montana
County				Big Horn
Stream				Bighorn
Latitude				45° 18.8'
Longitude				107° 55.0'
Owner				Water Power Resrouces Service
PHYSICAL				
Net Power Head - Ft.				26
Max. Storage - Acre-Ft.				520
Rated Discharge - C.F.S.				5,346

Power	Existing	New Potential	Total
Installed Capacity - KW	0	10,000	10,000
Average Annual Energy - MWH	0	51,800	51,800
Average Annual Plant Factor - %		----	59
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	18.82	----
Average Annual Cost - $	----	974,700	----
Average Annual Benefits - $	----	1,348,900	----
Net Benefits - $	----	374,200	----
B/C	----	1.38	----


MTAMR00660
BM 3301
3322
3298
BM 3282
3184
3200
3216
3262 LANDING STRIP
BM 3271
Substation
Gaging Stations
Fort Smith Ruins
Yellowtail Afterbay Dam
BR 3196
Cem
3192
Sewage Disposal Ponds
Fort Smith
3284
3281
3278
WT
CANYON
Water Tank
AREA
RECREATION
BOUNDARY
RESERVATION
CROW INDIAN
3606
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
7000 FEET

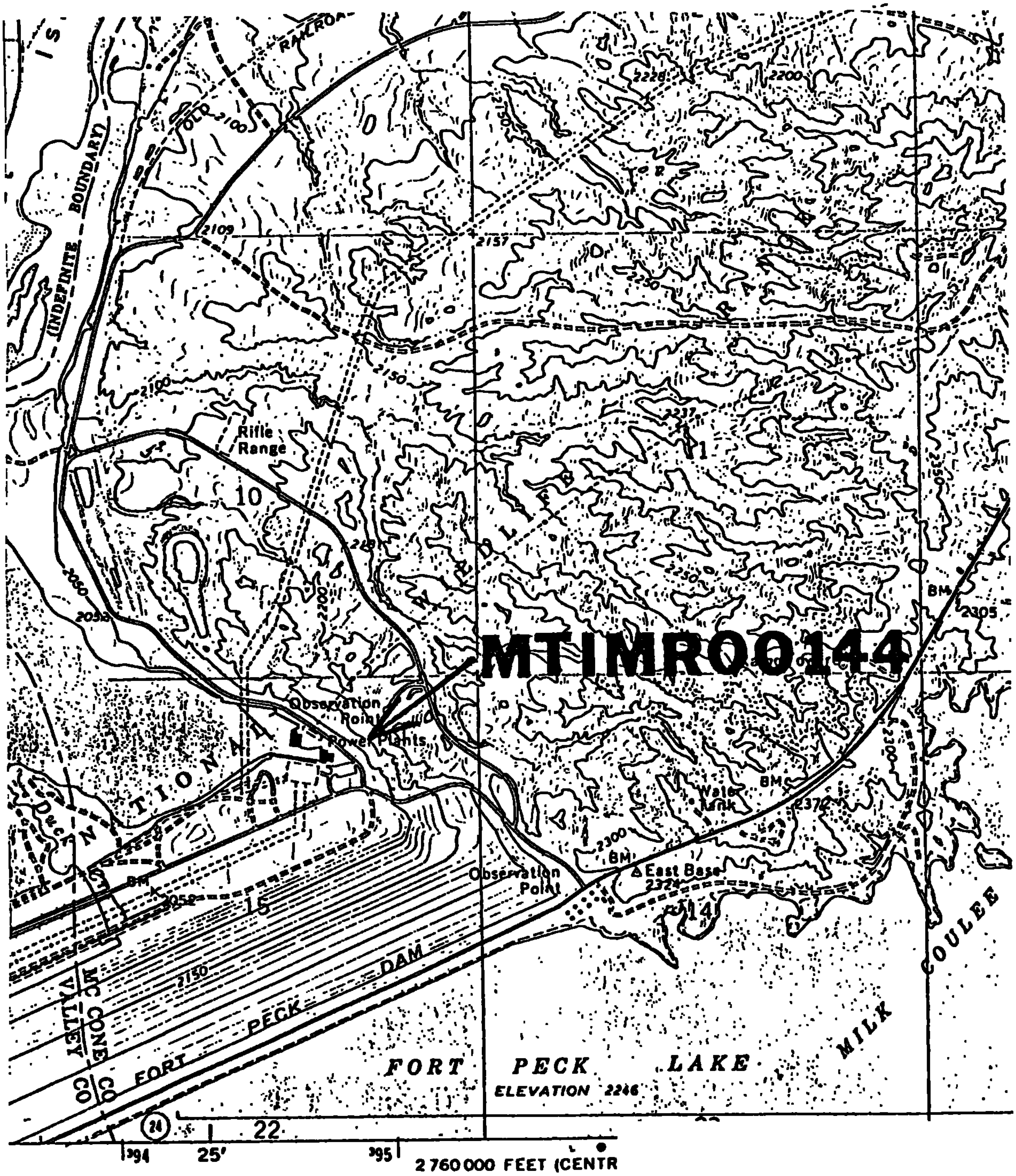
PERTINENT DATA

Lake Fort Peck

ID # MTIMR00144

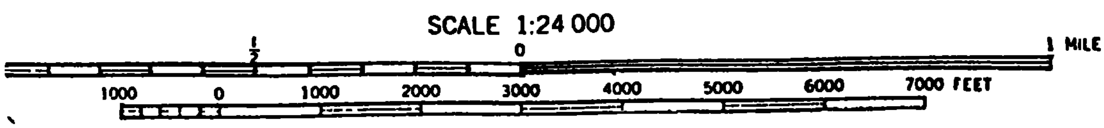
ITEM			DESCRIPTION
Location			
State			Montana
County			Garfield
Stream			Missouri River
Latitude			47° 59.0'
Longitude			106° 24.0'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			215
Max. Storage - Acre-Ft.			18,900,000
Rated Discharge - C.F.S.			32,600

Power	Existing	New Potential	Total
Installed Capacity - KW	165,000	185,000	350,000
Average Annual Energy - MWH	1,019,000	-26,300	992,700
Average Annual Plant Factor - %	70	----	32
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	-	----
Average Annual Cost - $	----	5,608,000	----
Average Annual Benefits - $	----	7,909,000	----
Net Benefits - $	----	2,841,000	----
B/C	----	1.4	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP



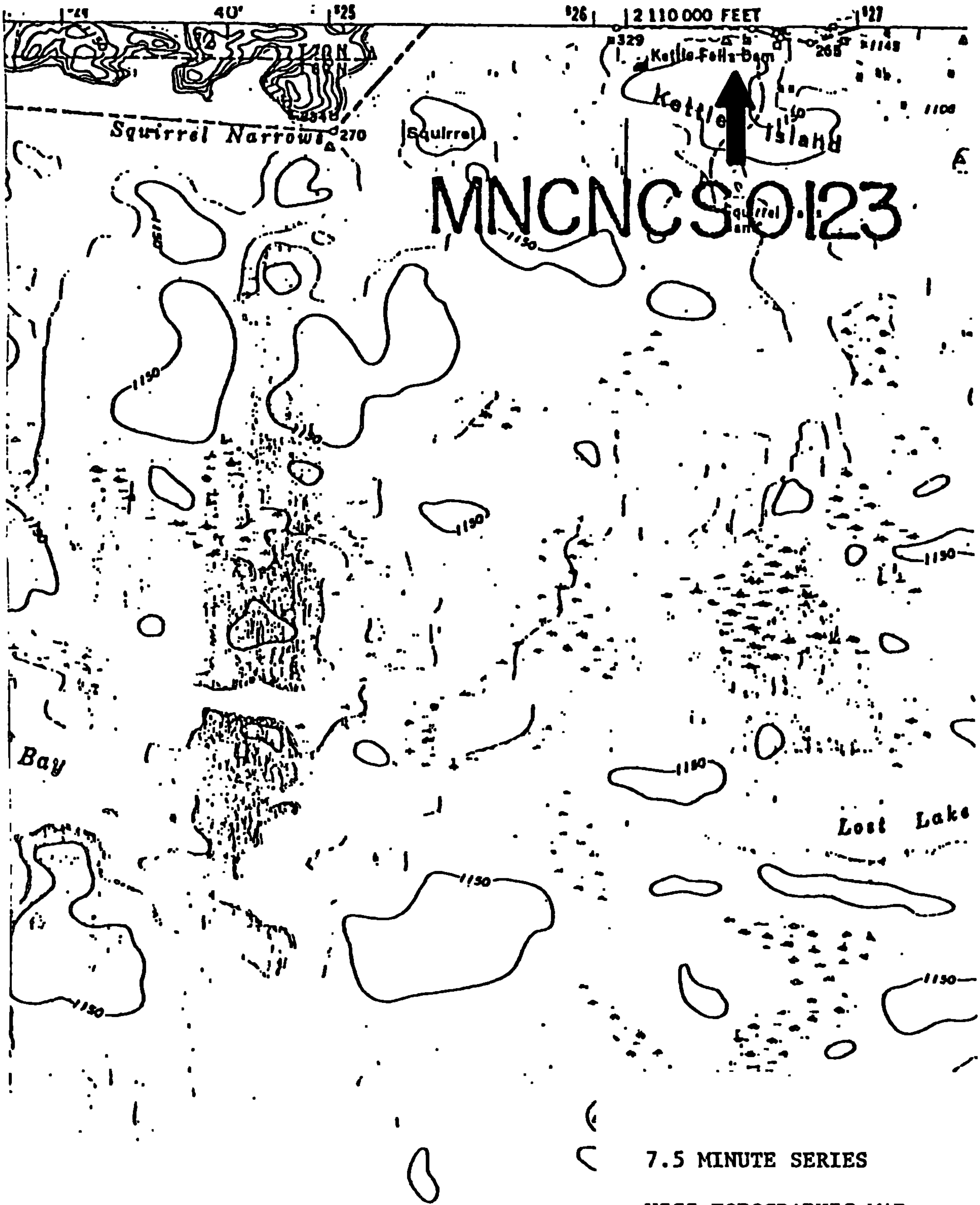
PERTINENT DATA

Kettle Falls

ID # MNCNCS0123

ITEM				DESCRIPTION
Location				
State				Minnesota
County				St. Louis
Stream				Rainy River
Latitude				48° 30.0'
Longitude				92° 38.2'
Owner				Minnesota and Ontario Power Co.
PHYSICAL				
Net Power Head - Ft.				18
Max. Storage - Acre-Ft.				702,500
Rated Discharge - C.F.S.				11,400

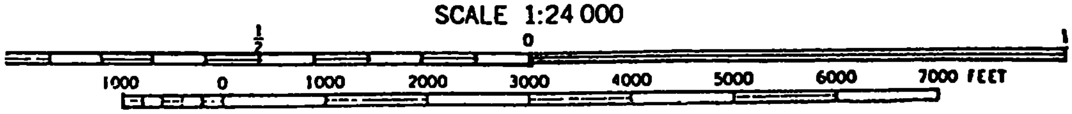
Power	Existing	New Potential	Total
Installed Capacity - KW	0	15,000	15,000
Average Annual Energy - MWH	0	90,500	90,500
Average Annual Plant Factor - %	0	----	69
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	15.30	----
Average Annual Cost - $	----	1,383,900	----
Average Annual Benefits - $	----	2,309,700	----
Net Benefits - $	----	925,800	----
B/C	----	1.67	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000



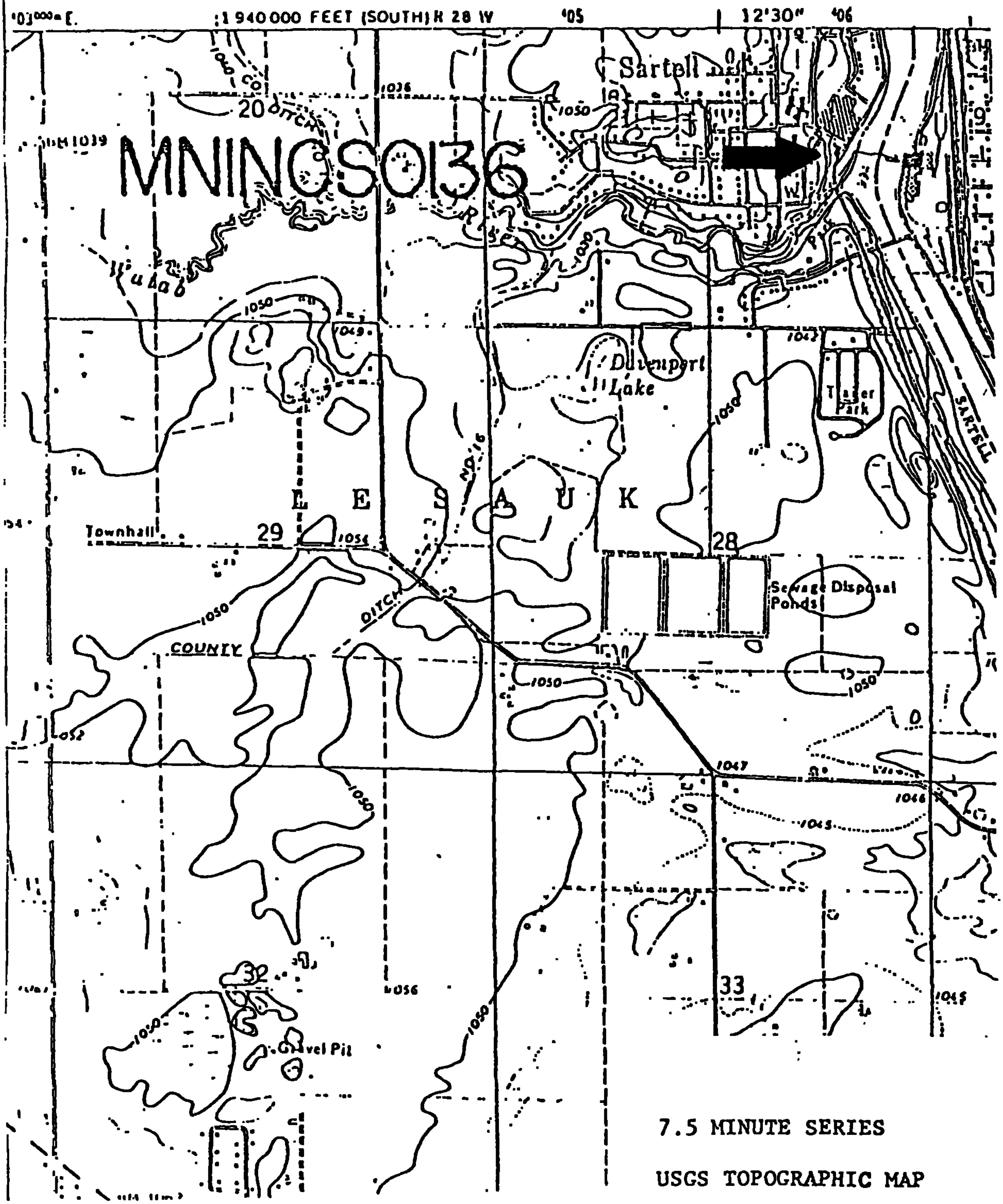
PERTINENT DATA

Sartell

ID # MNINCS0136

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Stearns
Stream			Mississippi
Latitude			45° : 37.1'
Longitude			94° 12.1'
Owner			St. Regis Paper Co.
PHYSICAL			
Net Power Head - Ft.			21
Max. Storage - Acre-Ft.			28,000
Rated Discharge - C.F.S.			10,000
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	3,200	13,000	16,200
Average Annual Energy - MWH	10,000	48,100	58,100
Average Annual Plant Factor - %	36	----	41
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	19.18	----
Average Annual Cost - $	----	922,700	----
Average Annual Benefits - $	----	1,487,700	----
Net Benefits - $	----	565,000	----
B/C	----	1.61	----

MENT OF THE INTERIOR
OLOGICAL SURVEY



SCALE 1:24 000

1/2 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

St. Cloud

ID # NMANCS0330

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Stearns
Stream			Mississippi
Latitude			45° 32.8'
Longitude			94° 8.8'
Owner			City of St. Cloud
PHYSICAL			
Net Power Head - Ft.			21.5
Max. Storage - Acre-Ft.			700
Rated Discharge - C.F.S.			,400
Power	Existing	New Potential	Total
Installed Capacity - KW	0	11,000	11,000
Average Annual Energy - MWH	0	42,700	42,000
Average Annual Plant Factor - %	0	----	44
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	26.93	----
Average Annual Cost - $	----	1,151,000	----
Average Annual Benefits - $	----	1,347,900	----
Net Benefits - $	----	196,900	----
B/C	----	1.17	----

15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

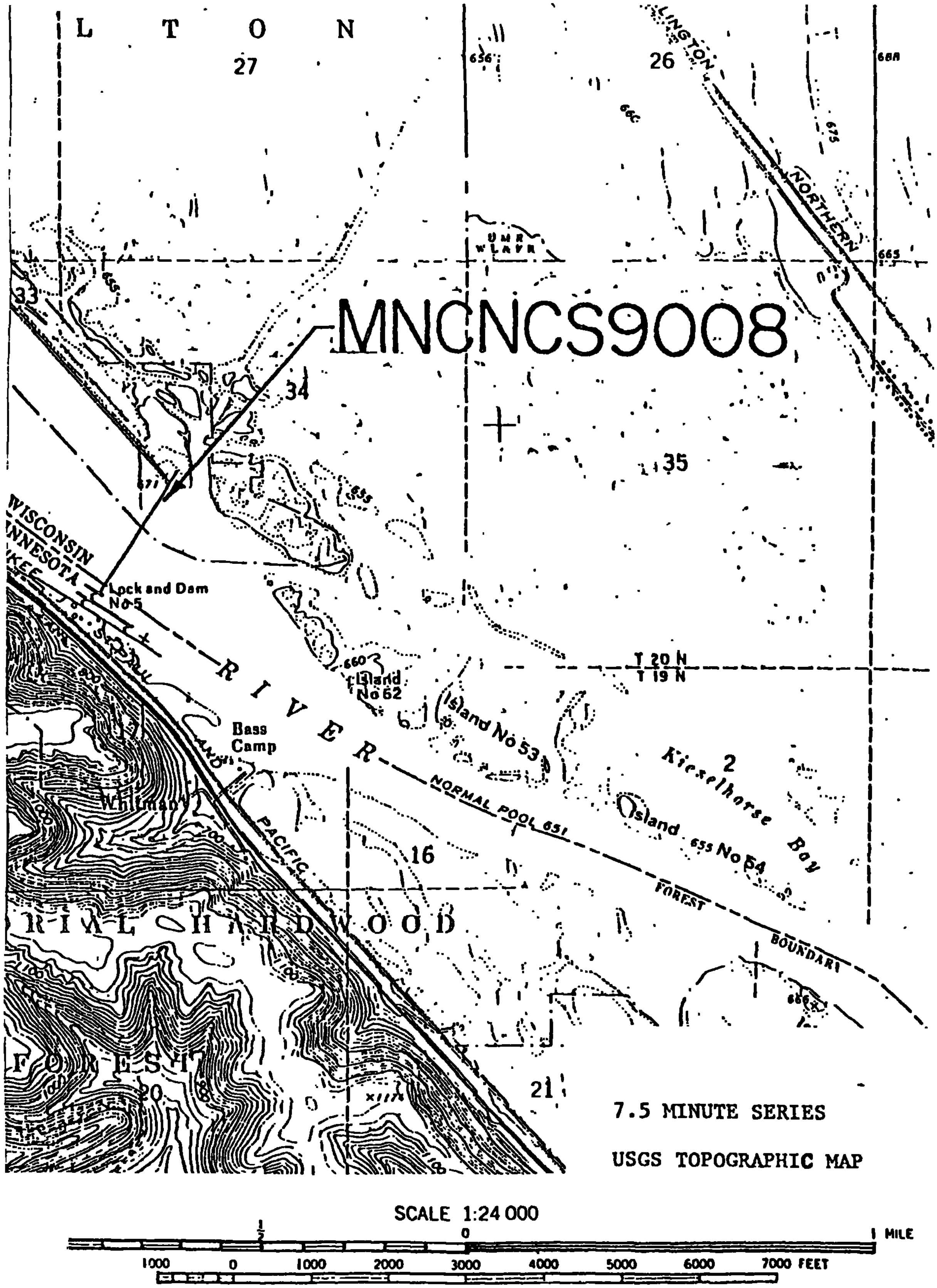
0 1 2 3 4 MILES

PERTINENT DATA

Lock 5

ID #MNØNCS9008

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Winona
Stream			Mississippi
Latitude			44° 9.6'
Longitude			91° 48.6'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			8.5
Max. Storage - Acre-Ft.			106,600
Rated Discharge - C.F.S.			9,375
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	0	5,808	5,808
Average Annual Energy - MWH	0	45,041	45,041
Average Annual Plant Factor - %	0	----	89
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	17.65	----
Average Annual Cost - $	----	794,963	----
Average Annual Benefits - $	----	1,088,936	----
Net Benefits - $	----	293,973	----
B/C	----	1.37	----


MNCNCS9008
L T O N
27
26
34
35
33
WISCONSIN
MINNESOTA
Lock and Dam No 5
RIVER
Island No 62
Island No 53
Island No 54
Kieselhorse Bay
Bass Camp
NORMAL POOL 651
FOREST BOUNDARY
T 20 N
T 19 N
PACIFIC
NORTHERN
16
2
21
20
RIAL HARDWOOD
FOREST
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
7000 FEET

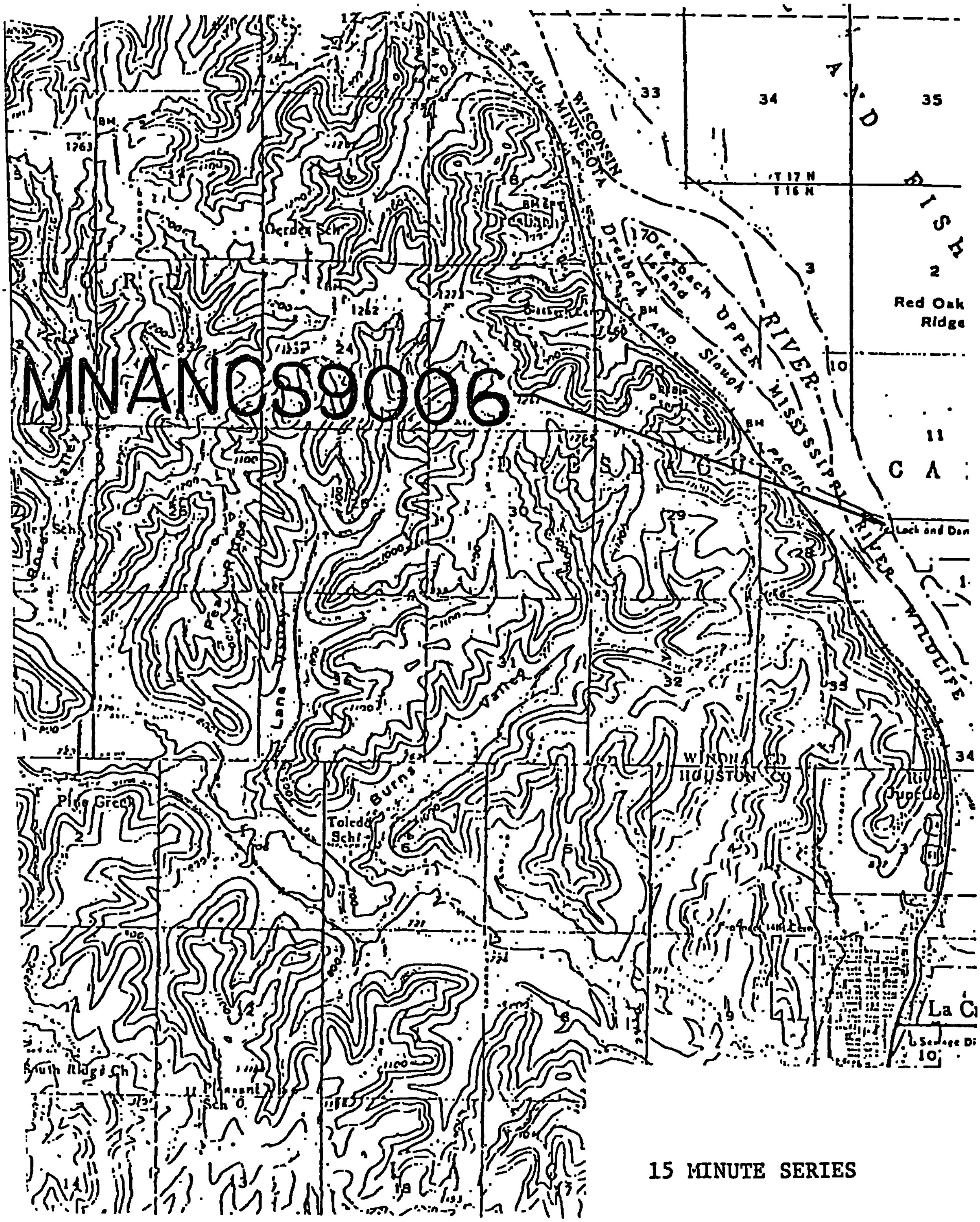
PERTINENT DATA

Lock 7

ID # MNANCS9006

ITEM				DESCRIPTION
Location				
State				Minnesota
County				Winona
Stream				Mississippi
Latitude				43° 51.9'
Longitude				91° 18.5'
Owner				Army Corps of Engineers
PHYSICAL				
Net Power Head - Ft.				8
Max. Storage - Acre-Ft.				105,000
Rated Discharge - C.F.S.				29,200

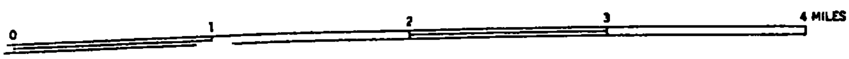
Power	Existing	New Potential	Total
Installed Capacity - KW	0	12,700	12,700
Average Annual Energy - MWH	0	64,700	64,700
Average Annual Plant Factor - %	0	----	58
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	25.36	----
Average Annual Cost - $	----	1,640,100	----
Average Annual Benefits - $	----	1,739,800	----
Net Benefits - $	----	99,700	----
B/C	----	1.06	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

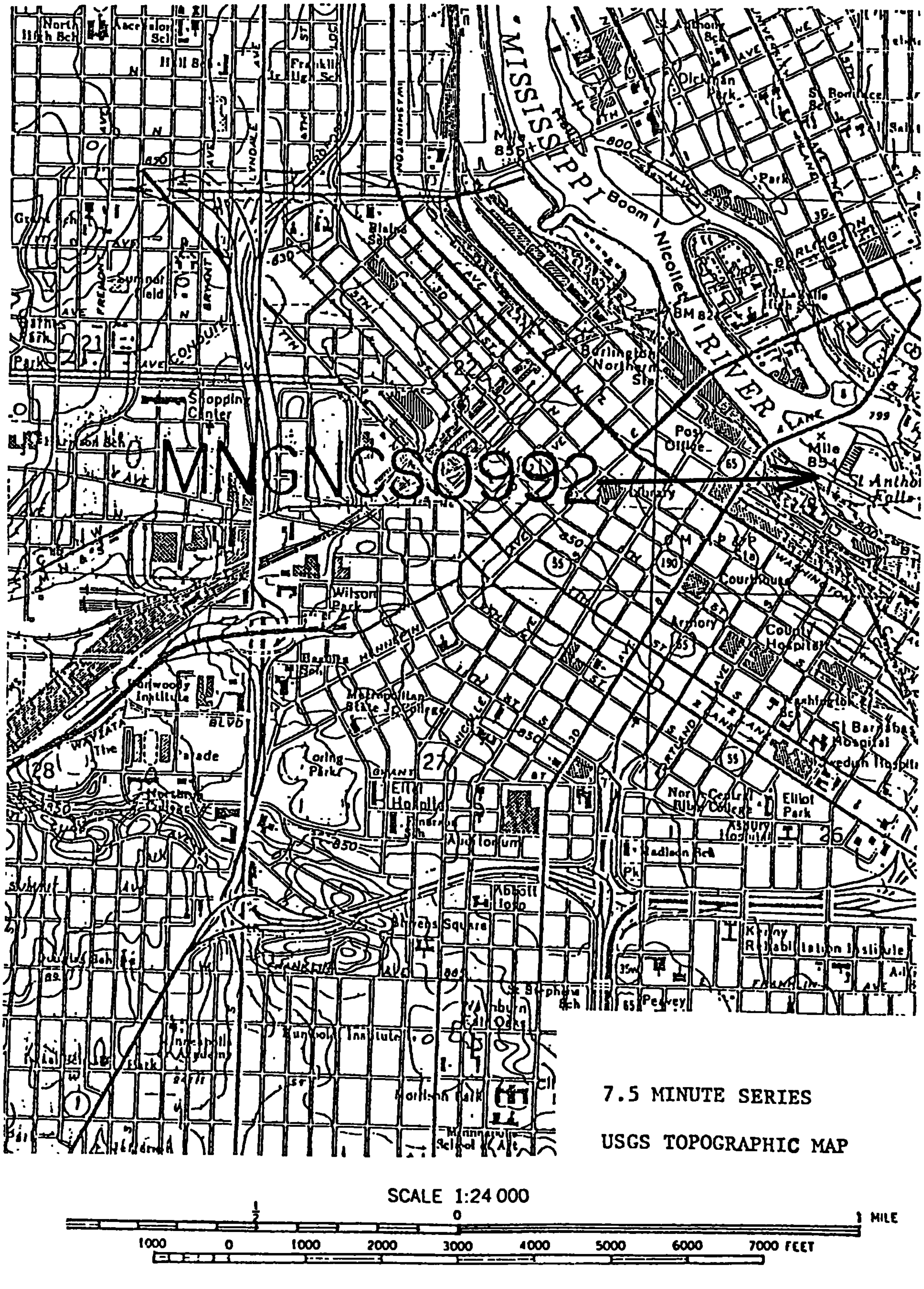


PERTINENT DATA

Hennepin I

ID #MNGNCS0992

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Hennepin
Stream			Mississippi
Latitude			44° 58.8'
Longitude			93° 15.4'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			49
Max. Storage - Acre-Ft.			4,900
Rated Discharge - C.F.S.			6,200
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	12,400	9,900	22,300
Average Annual Energy - MWH	91,500	53,400	144,900
Average Annual Plant Factor - %	84	----	74
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	8.13	----
Average Annual Cost - $	----	433,900	----
Average Annual Benefits - $	----	1,206,400	----
Net Benefits - $	----	772,500	----
B/C	----	2.78	----



7.5 MINUTE SERIES

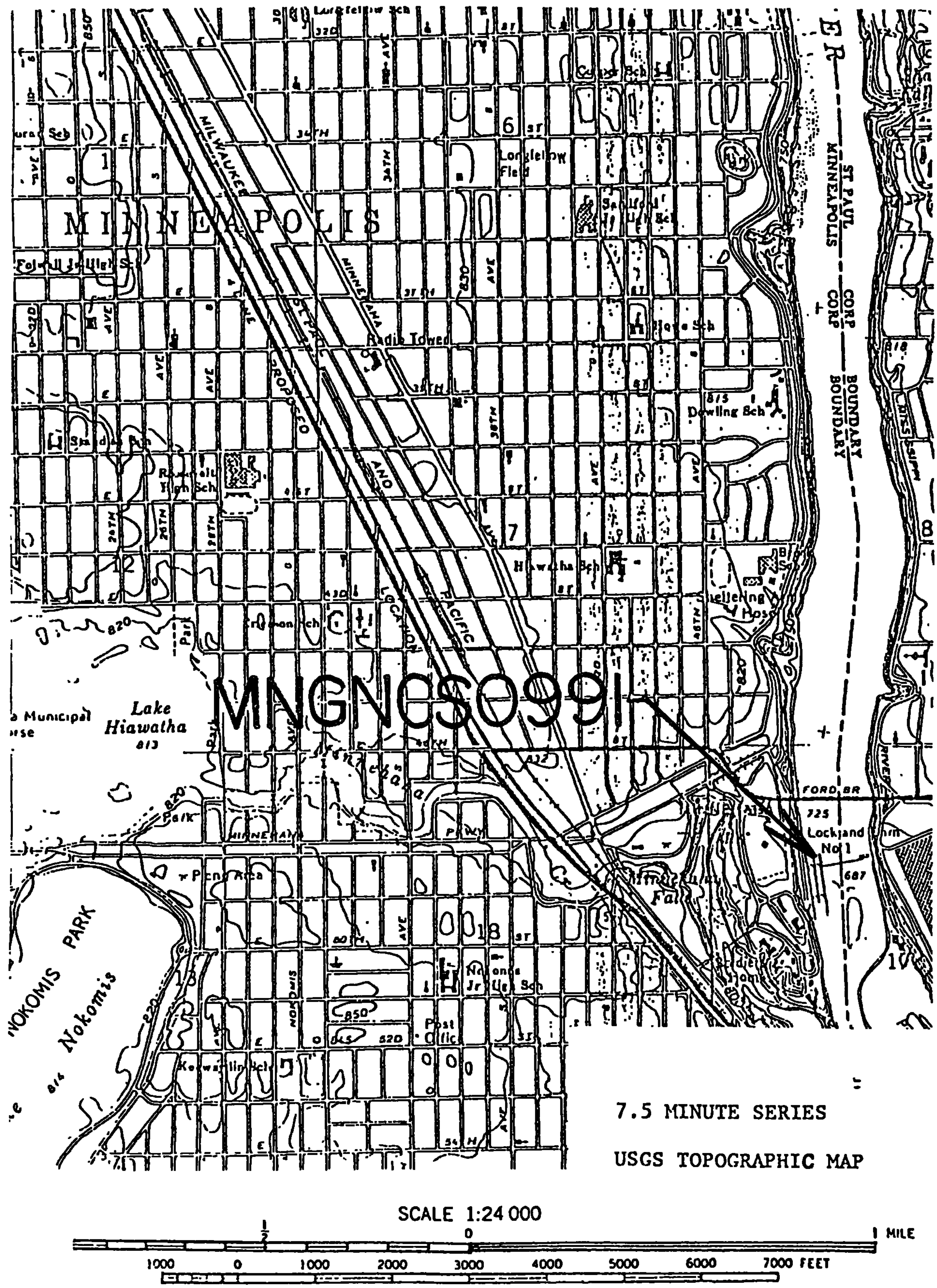
USGS TOPOGRAPHIC MAP

PERTINENT DATA

Lock 1

ID # MNGNCS0991

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Hennepin
Stream			Mississippi
Latitude			44° 54.8'
Longitude			93° 12.1'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			36
Max. Storage - Acre-Ft.			9,300
Rated Discharge - C.F.S.			6,200
Power	Existing	New Potential	Total
Installed Capacity - KW	14,400	1,900	16,300
Average Annual Energy - MWH	87,000	19,100	106,100
Average Annual Plant Factor - %	69	----	74
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	4.20	----
Average Annual Cost - $	----	80,400	----
Average Annual Benefits - $	----	315,100	----
Net Benefits - $	----	234,700	----
B/C	----	3.92	----



MINNEAPOLIS
MNGNCS0991
Longfellow Field
Radio Tower
Dowling Sch
Hiawatha Sch
Roosevelt High Sch
Lake Hiawatha
813
NOKOMIS PARK
Lake Nokomis
Nokomis Jr High Sch
Post Office
MILWAUKEE
MINNEHAHA
PACIFIC
FORD BR
Lockland Dam No 1
ST PAUL
MINNEAPOLIS
CORP
CORP
BOUNDARY
BOUNDARY
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1/2
0
1 MILE
1000
0
1000
2000
3000
4000
5000
6000
7000 FEET

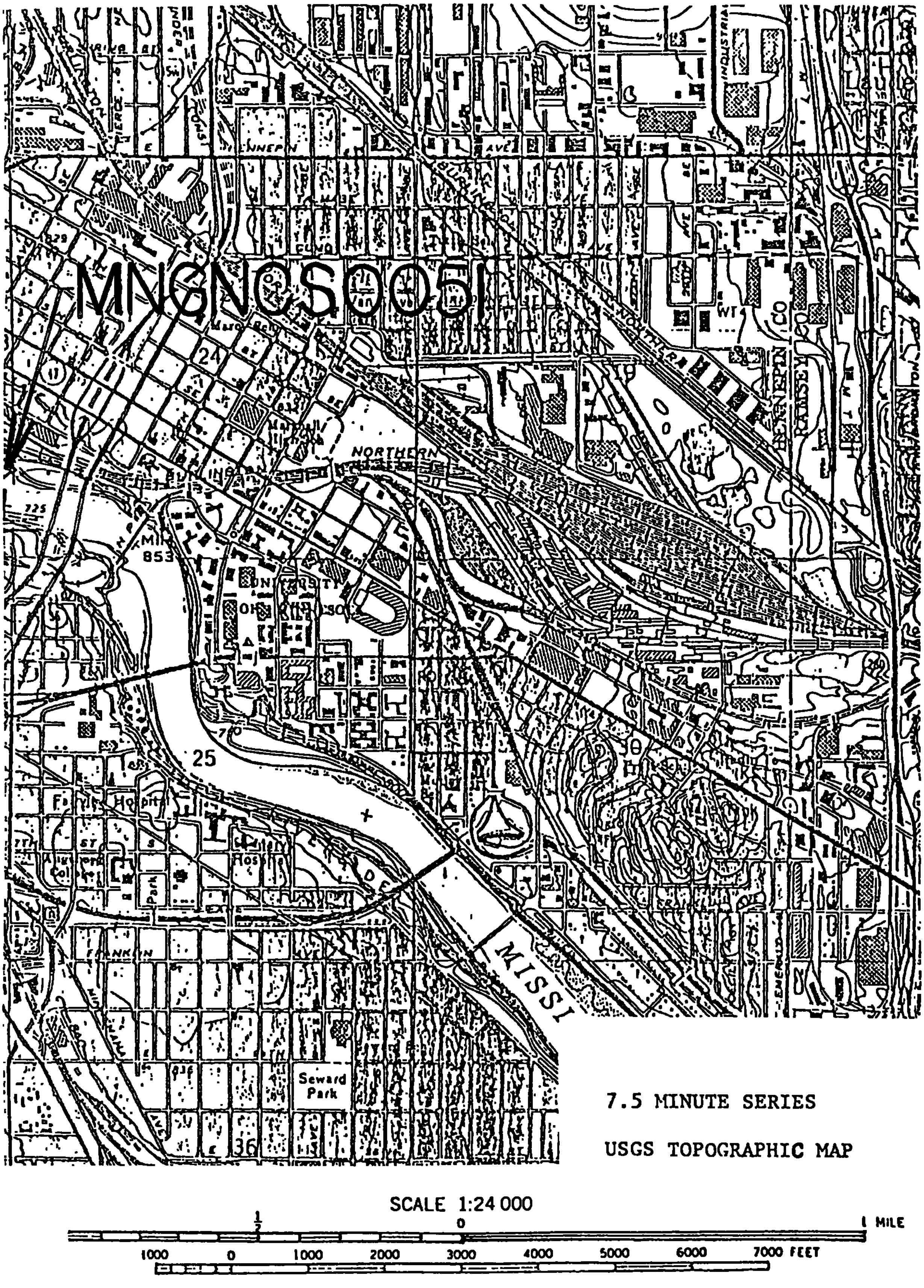
PERTINENT DATA

Lower Dam

ID # MNGNCS0051

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Hennepin
Stream			Mississippi
Latitude			44° 58.2'
Longitude			93° 14.8'
Owner			Northern States Power Co.
PHYSICAL			
Net Power Head - Ft.			27
Max. Storage - Acre-Ft.			420
Rated Discharge - C.F.S.			11,000

Power	Existing	New Potential	Total
Installed Capacity - KW	8,000	13,600	21,600
Average Annual Energy - MWH	49,300	53,600	102,900
Average Annual Plant Factor - %		----	54
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	14.97	----
Average Annual Cost - $	----	802,800	----
Average Annual Benefits - $	----	1,466,400	----
Net Benefits - $	----	663,600	----
B/C	----	1.83	----

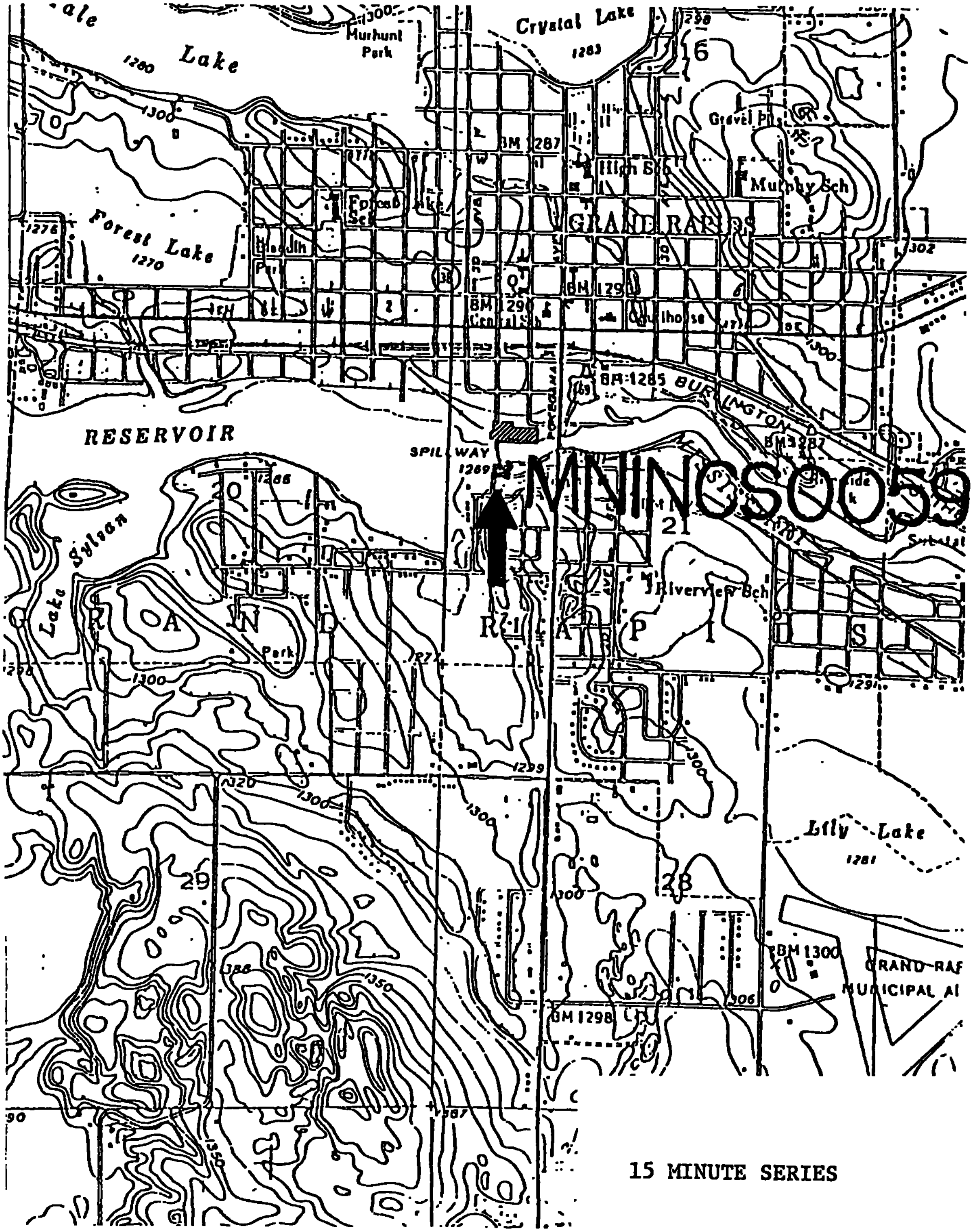

MNGNCS005I
NORTHERN
UNIVERSITY OF MINNESOTA
Seward Park
MISSI
24
25
36
853
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Blandin

ID # MNINCS0059

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Itasca
Stream			Mississippi
Latitude			47° 13.8'
Longitude			93° 31.8'
Owner			Blandin Paper Company
PHYSICAL			
Net Power Head - Ft.			20
Max. Storage - Acre-Ft.			10,400
Rated Discharge - C.F.S.			3,600
Power	Existing	New Potential	Total
Installed Capacity - KW	2,100	3,200	5,300
Average Annual Energy - MWH	10,000	7,500	17,500
Average Annual Plant Factor - %	54	----	38
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	28.54	----
Average Annual Cost - $	----	214,700	----
Average Annual Benefits - $	----	301,900	----
Net Benefits - $	----	87,200	----
B/C	----	1.41	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500

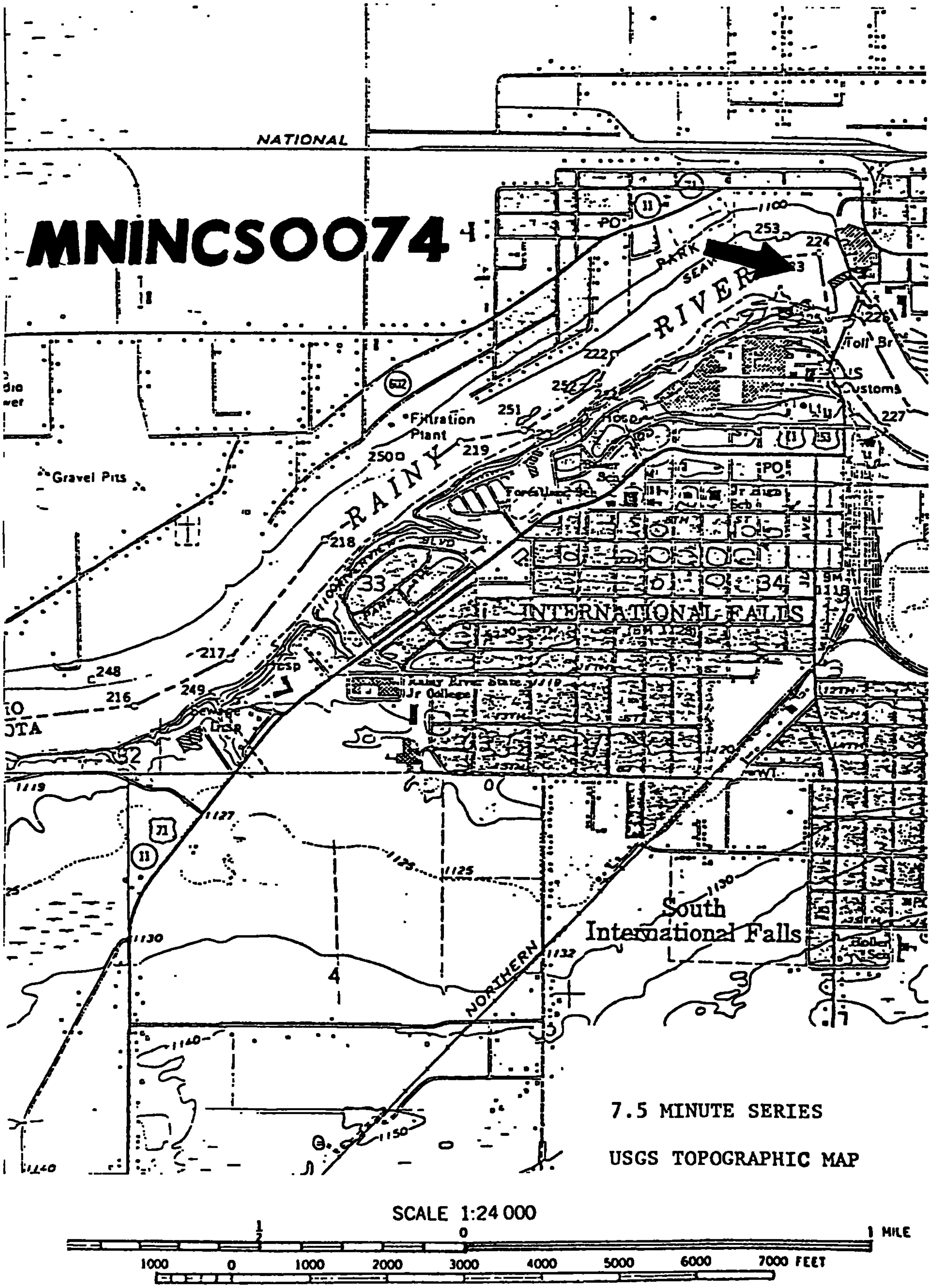
0 1 2 3 4 MILES

PERTINENT DATA

Rainy Lake

ID # MNINCS0074

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Koochiching
Stream			Rainy River
Latitude			48 ° 36.3'
Longitude			93 ° 24.0'
Owner			Boise-Cascade Corp.
PHYSICAL			
Net Power Head - Ft.			20
Max. Storage - Acre-Ft.			4,000,000
Rated Discharge - C.F.S.			2,700
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	5,600	59,000	64,600
Average Annual Energy - MWH	25,000	190,300	215,300
Average Annual Plant Factor - %	51	----	38
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	22.21	----
Average Annual Cost - $	----	4,226,900	----
Average Annual Benefits - $	----	6,344,900	----
Net Benefits - $	----	2,118,000	----
B/C	----	1.50	----


MNINCS0074
NATIONAL
RAINY RIVER
Filtration Plant
Gravel Pits
INTERNATIONAL FALLS
South International Falls
Rainy River State Jr College
Toll Br
US Customs
NORTHERN
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
7000 FEET

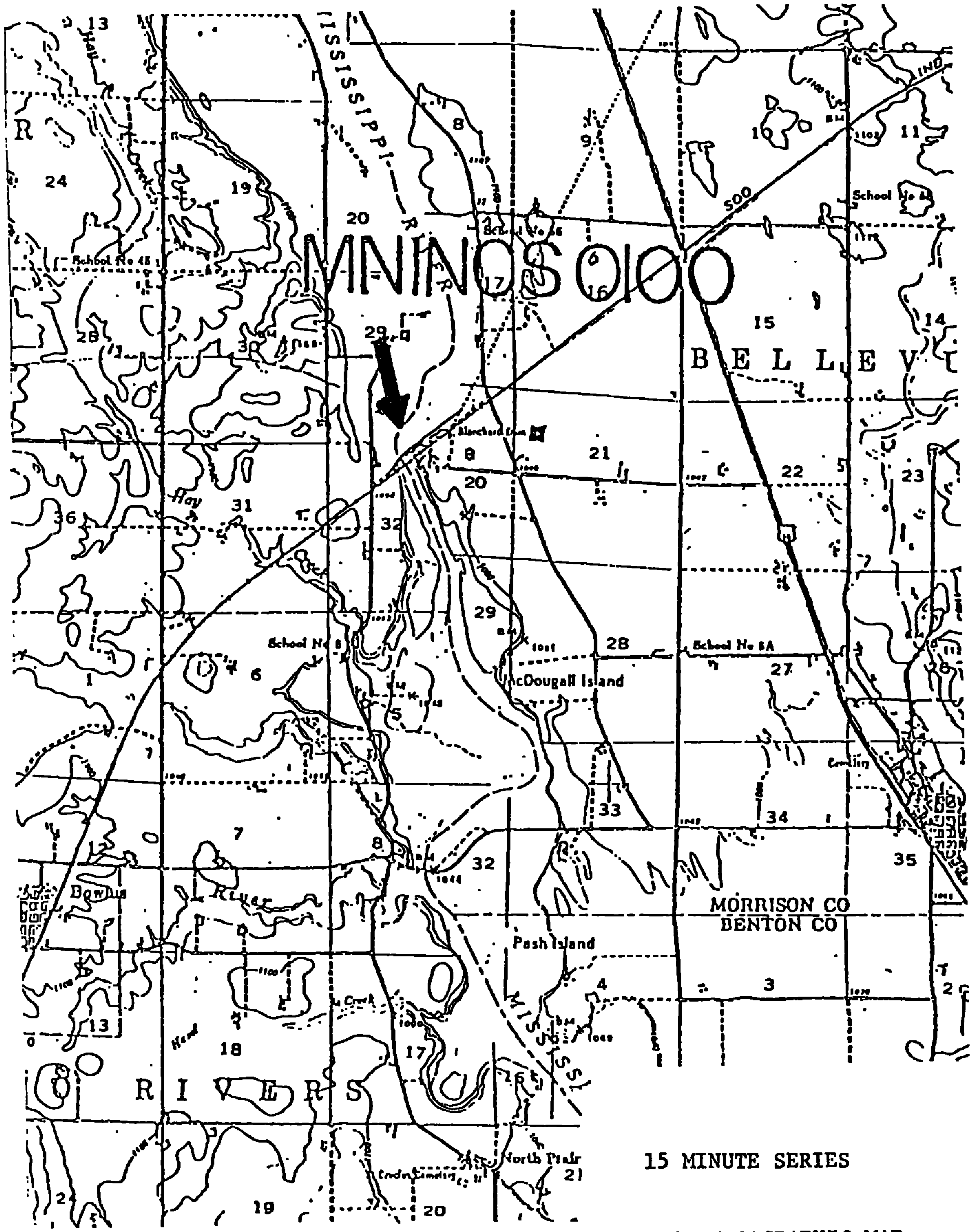
PERTINENT DATA

Blanchard

ID # MNINCS0100

ITEM	DESCRIPTION
Location	
State	Minnesota
County	Morrison
Stream	Mississippi
Latitude	45 o 51.5
Longitude	94 o 20.4
Owner	Minnesota Power & Light Co.
PHYSICAL	
Net Power Head - Ft.	45
Max. Storage - Acre-Ft.	15,500
Rated Discharge - C.F.S.	20,800

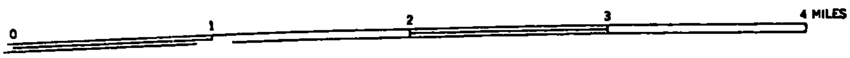
Power	Existing	New Potential	Total
Installed Capacity - KW	12,000	56,300	68,300
Average Annual Energy - MWH	79,100	44,400	123,500
Average Annual Plant Factor - %	75	----	21
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	74.43	----
Average Annual Cost - $	----	3,305,100	----
Average Annual Benefits - $	----	3,812,300	----
Net Benefits - $	----	507,200	----
B/C	----	1.15	----



15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500



PERTINENT DATA

Pisgah

ID # MNGNCS0334

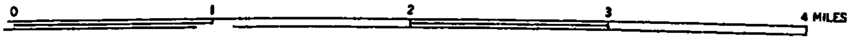
ITEM			DESCRIPTION
Location			
State			Minnesota
County			Otter Tail
Stream			Otter Tail
Latitude			46° 16.8'
Longitude			95° 6.1'
Owner			Otter Tail Power Co.
PHYSICAL			
Net Power Head - Ft.			27
Max. Storage - Acre-Ft.			250
Rated Discharge - C.F.S.			2,000

Power	Existing	New Potential	Total
Installed Capacity - KW	520	3,500	4,020
Average Annual Energy - MWH	3,600	6,200	9,800
Average Annual Plant Factor - %	79	----	28
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	39.03	----
Average Annual Cost - $	----	242,000	----
Average Annual Benefits - $	----	284,200	----
Net Benefits - $	----	42,200	----
B/C	----	1.17	----

15 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:62500



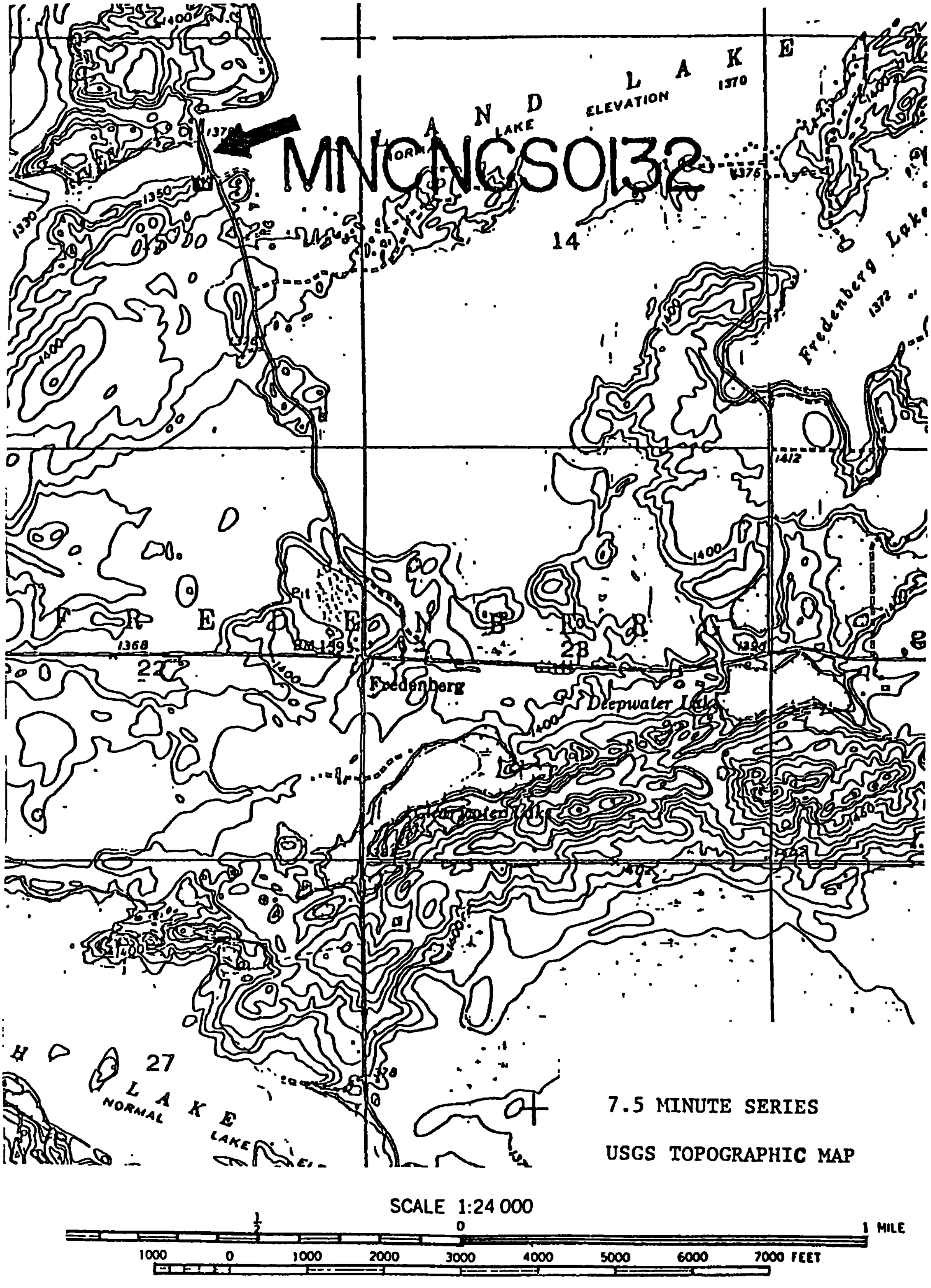
PERTINENT DATA

Island Lake

ID # MNCNCCS0132

ITEM			DESCRIPTION
Location			
State			Minnesota
County			St. Louis
Stream			Cloquet
Latitude			46° 59.4'
Longitude			92° 13.4'
Owner			Minnesota Power and Light Co.
PHYSICAL			
Net Power Head - Ft.			37
Max. Storage - Acre-Ft.			196,300
Rated Discharge - C.F.S.			1,800

Power	Existing	New Potential	Total
Installed Capacity - KW	0	4,800	4,800
Average Annual Energy - MWH	0	9,600	9,600
Average Annual Plant Factor - %	0	----	23
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	36.61	----
Average Annual Cost - $	----	353,100	----
Average Annual Benefits - $	----	424,100	----
Net Benefits - $	----	71,000	----
B/C	----	1.20	----

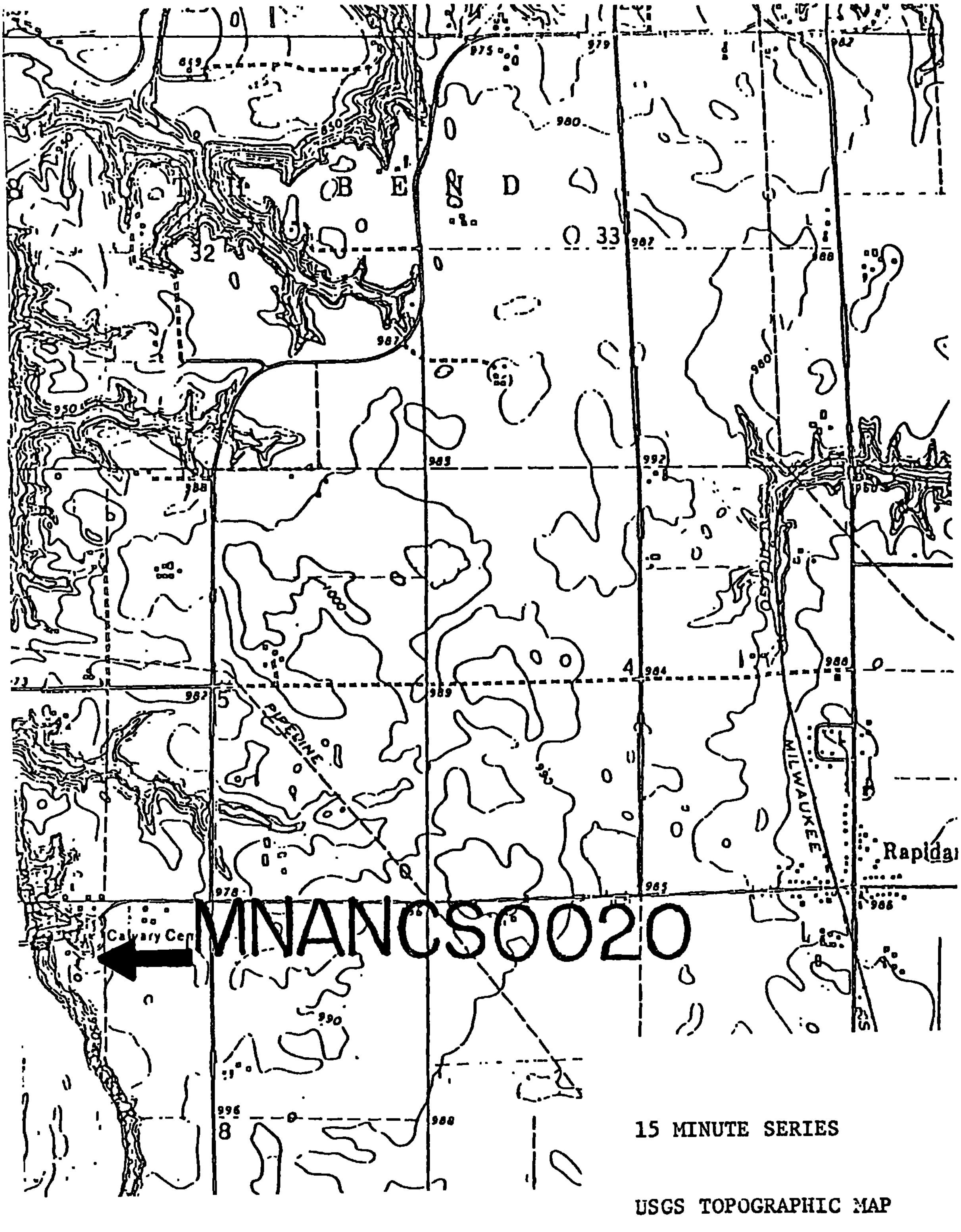

MNCNCS0132
L A K E
ELEVATION
1370
14
Fredenberg Lake
1412
1400
F R E D E N B E R
1368
22
23
Fredenberg
Deepwater Lake
27
L A K E
NORMAL
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1 MILE
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Rapidan

ID # MNANCS0020

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Blue Earth
Stream			Blue Earth
Latitude			44° 5.5'
Longitude			94° 6.4'
Owner			Blue Earth
PHYSICAL			
Net Power Head - Ft.			52
Max. Storage - Acre-Ft.			13,500
Rated Discharge - C.F.S.			1,100
Power	Existing	New Potential	Total
Installed Capacity - KW	0	5,800	5,800
Average Annual Energy - MWH	0	20,100	20,100
Average Annual Plant Factor - %	0	----	40
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	28.17	----
Average Annual Cost - $	----	567,200	----
Average Annual Benefits - $	----	650,700	----
Net Benefits - $	----	83,500	----
B/C	----	1.15	----



SCALE 1:62500

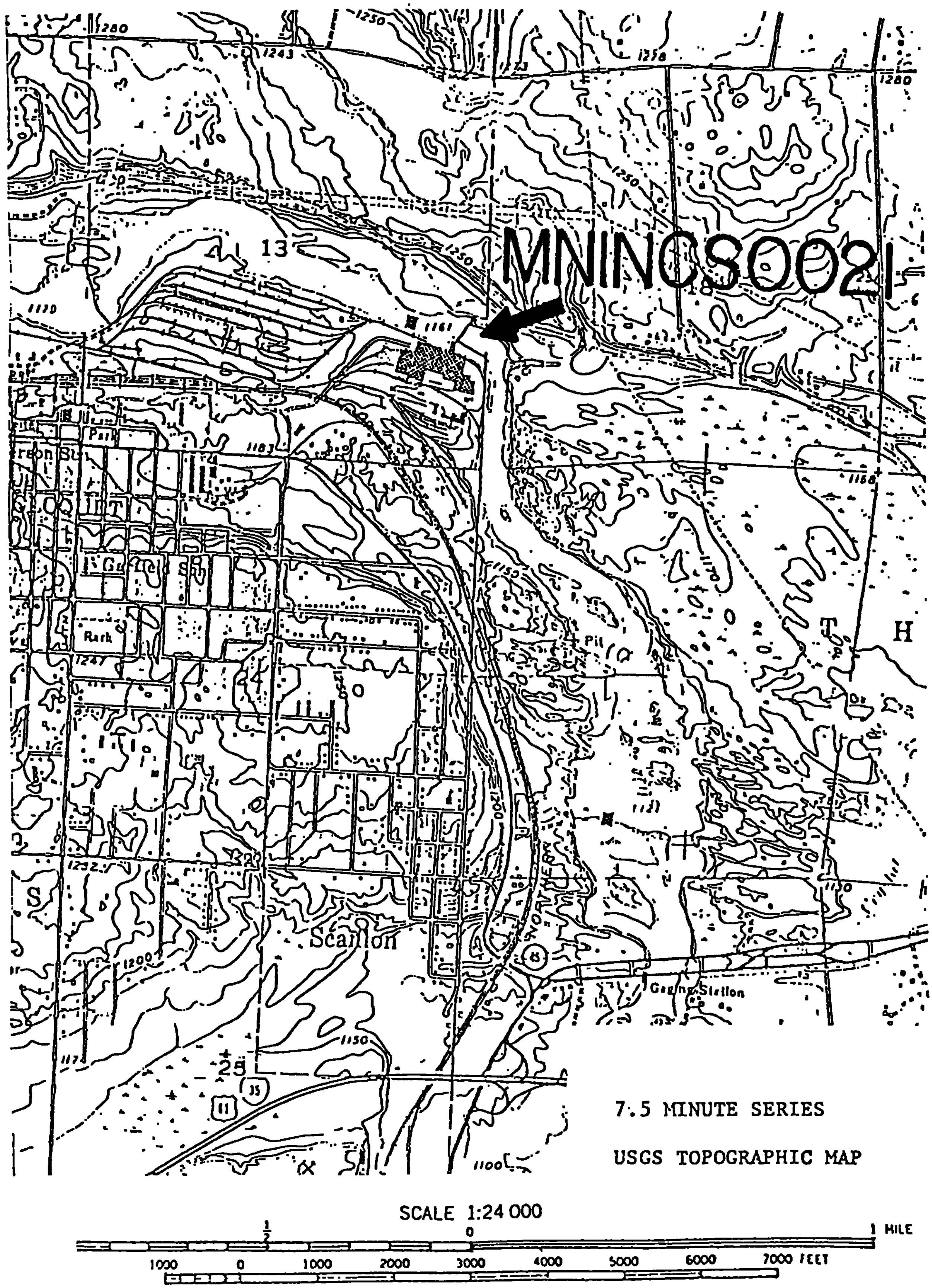
0 1 2 3 4 MILES

PERTINENT DATA

Cloquet

ID # MNINCS0021

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Carlton
Stream			St. Louis
Latitude			46° 43.2'
Longitude			92° 25.6'
Owner			Northwest Paper Co.
PHYSICAL			
Net Power Head - Ft.			36
Max. Storage - Acre-Ft.			700
Rated Discharge - C.F.S.			8,200
Power	Existing	New Potential	Total
Installed Capacity - KW	3,500	18,100	21,600
Average Annual Energy - MWH	29,700	18,900	48,600
Average Annual Plant Factor - %	97	----	26
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	48.59	----
Average Annual Cost - $	----	918,300	----
Average Annual Benefits - $	----	1,376,800	----
Net Benefits - $	----	458,500	----
B/C	----	1.50	----


MNINGS0021
13
Park
Scanlon
Gagne Station
Pit
1250
1150
1200
1100
25
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1/2
0
1 MILE
1000
0
1000
2000
3000
4000
5000
6000
7000 FEET

PERTINENT DATA

Fond du Lac

ID # MNANCS0022

ITEM				DESCRIPTION
Location				
State				Minnesota
County				Carlton
Stream				St. Louis
Latitude				46° 39.8'
Longitude				92° 17.6'
Owner				Minnesota Power & Light
PHYSICAL				
Net Power Head - Ft.				78
Max. Storage - Acre-Ft.				2,100
Rated Discharge - C.F.S.				3,000

Power	Existing	New Potential	Total
Installed Capacity - KW	12,000	5,100	17,100
Average Annual Energy - MWH	63,300	18,300	81,600
Average Annual Plant Factor - %	60	----	54
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	14.61	----
Average Annual Cost - $	----	267,800	----
Average Annual Benefits - $	----	535,900	----
Net Benefits - $	----	268,100	----
B/C	----	2.0	----

7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

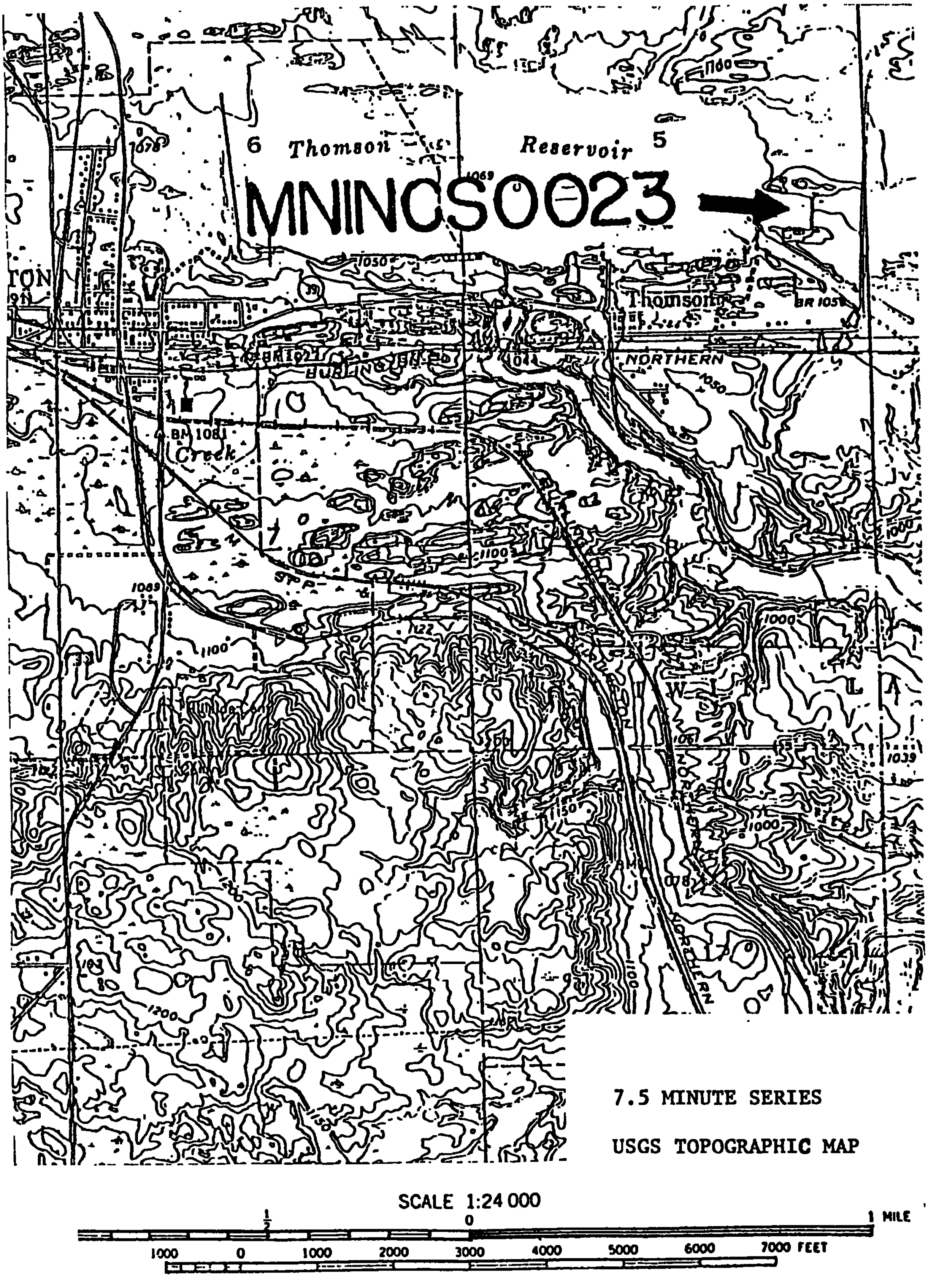
PERTINENT DATA

Thomson

ID # MNINCS0023

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Carlton
Stream			St. Louis
Latitude			46° 39.8'
Longitude			92° 24.4'
Owner			Minnesota Power & Light Co.
PHYSICAL			
Net Power Head - Ft.			368
Max. Storage - Acre-Ft.			4,200
Rated Discharge - C.F.S.			1,133

Power	Existing	New Potential	Total
Installed Capacity - KW	69,600	30,400	100,000
Average Annual Energy - MWH	318,000	271,423	589,423
Average Annual Plant Factor - %	52	----	54
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	1.87	----
Average Annual Cost - $	----	507,500	----
Average Annual Benefits - $	----	4,705,900	----
Net Benefits - $	----	4,198,400	----
B/C	----	9.27	----



7.5 MINUTE SERIES

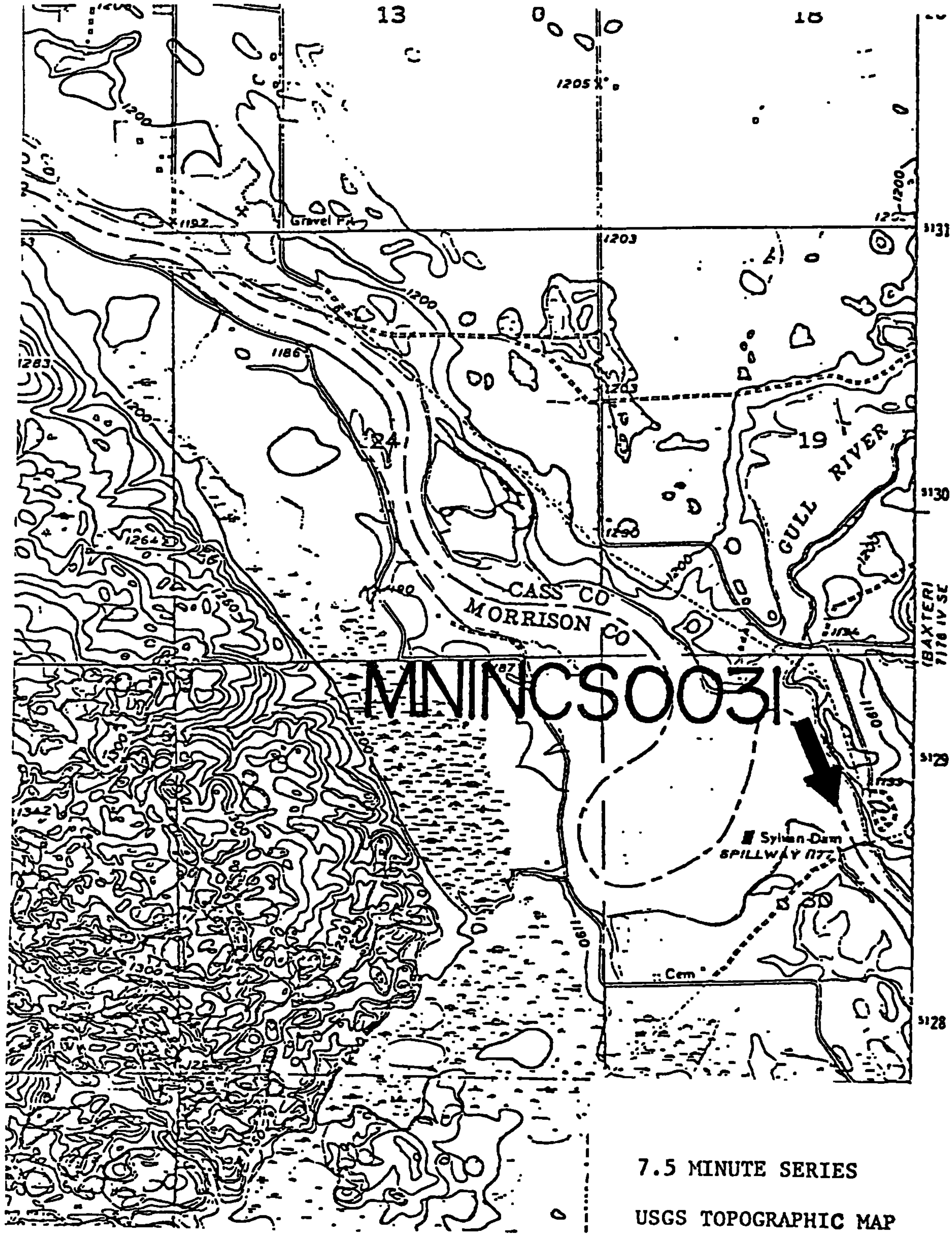
USGS TOPOGRAPHIC MAP

PERTINENT DATA

Sylvan

ID # MNINCS0031

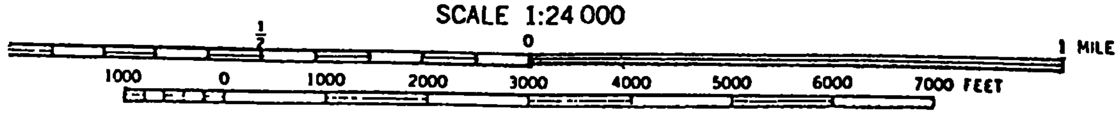
ITEM			DESCRIPTION
Location			
State			Minnesota
County			Cass
Stream			Crow Wing
Latitude			41° 18.3'
Longitude			94° 22.7'
Owner			Minnesota Power & Light
PHYSICAL			
Net Power Head - Ft.			22
Max. Storage - Acre-Ft.			10,100
Rated Discharge - C.F.S.			3,400
Power	Existing	New Potential	Total
Installed Capacity - KW	1,800	3,700	5,500
Average Annual Energy - MWH	9,800	8,000	17,800
Average Annual Plant Factor - %	62	----	37
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	30.52	----
Average Annual Cost - $	----	244,300	----
Average Annual Benefits - $	----	336,400	----
Net Benefits - $	----	92,100	----
B/C	----	1.38	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

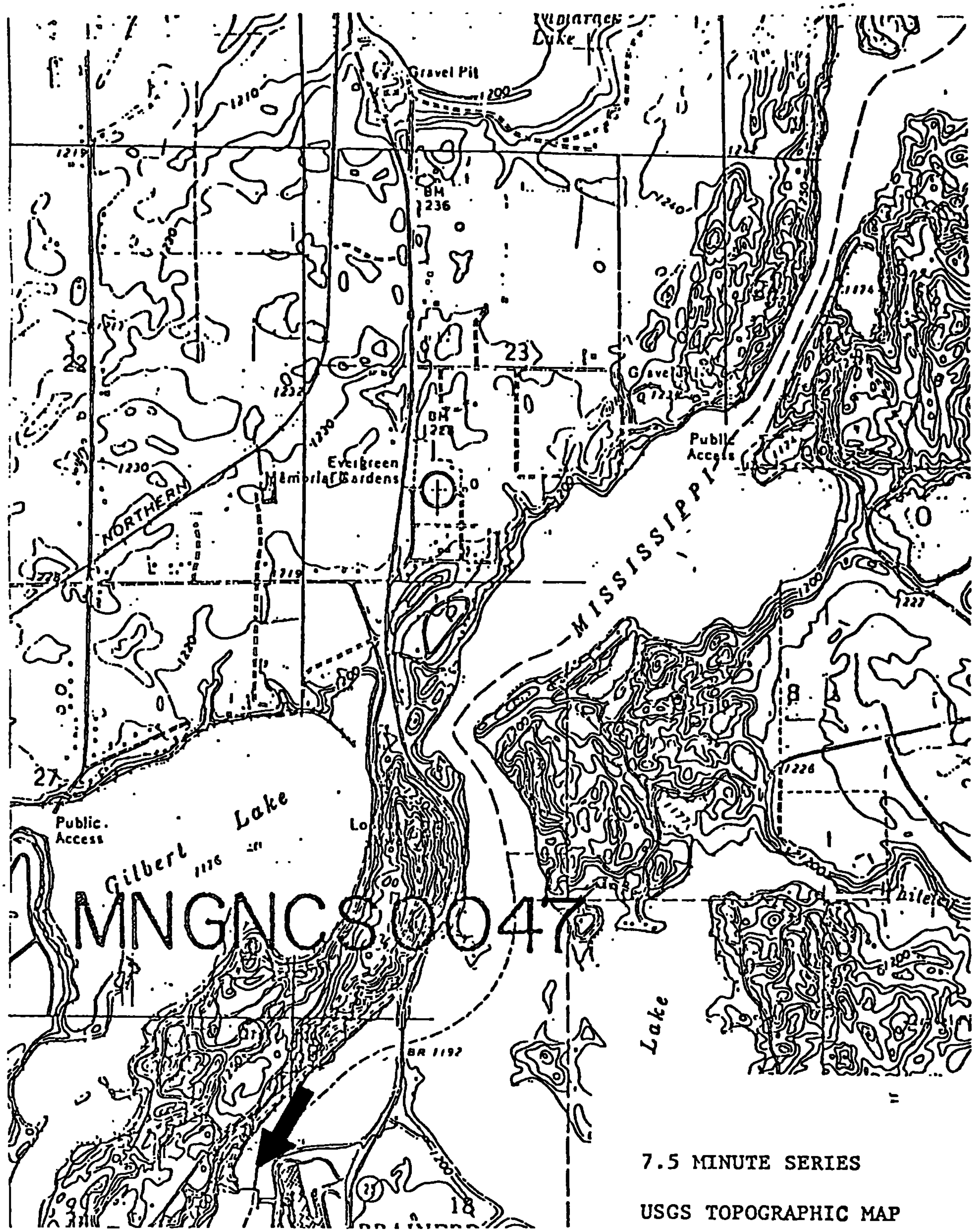


PERTINENT DATA

Brainerd

ID # MNGNCS0047

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Crow Wing
Stream			Mississippi
Latitude			46° 22.6'
Longitude			94° 11.0'
Owner			Northwest Paper Co.
PHYSICAL			
Net Power Head - Ft.			20
Max. Storage - Acre-Ft.			1,600
Rated Discharge - C.F.S.			7,000
Power	Existing	New Potential	Total
Installed Capacity - KW	3,300	7,000	10,300
Average Annual Energy - MWH	16,600	24,000	40,600
Average Annual Plant Factor - %	57	----	45
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	21.68	----
Average Annual Cost - $	----	520,100	----
Average Annual Benefits - $	----	750,000	----
Net Benefits - $	----	229,900	----
B/C	----	1.44	----



SCALE 1:24 000

1/2 0 1 MILE

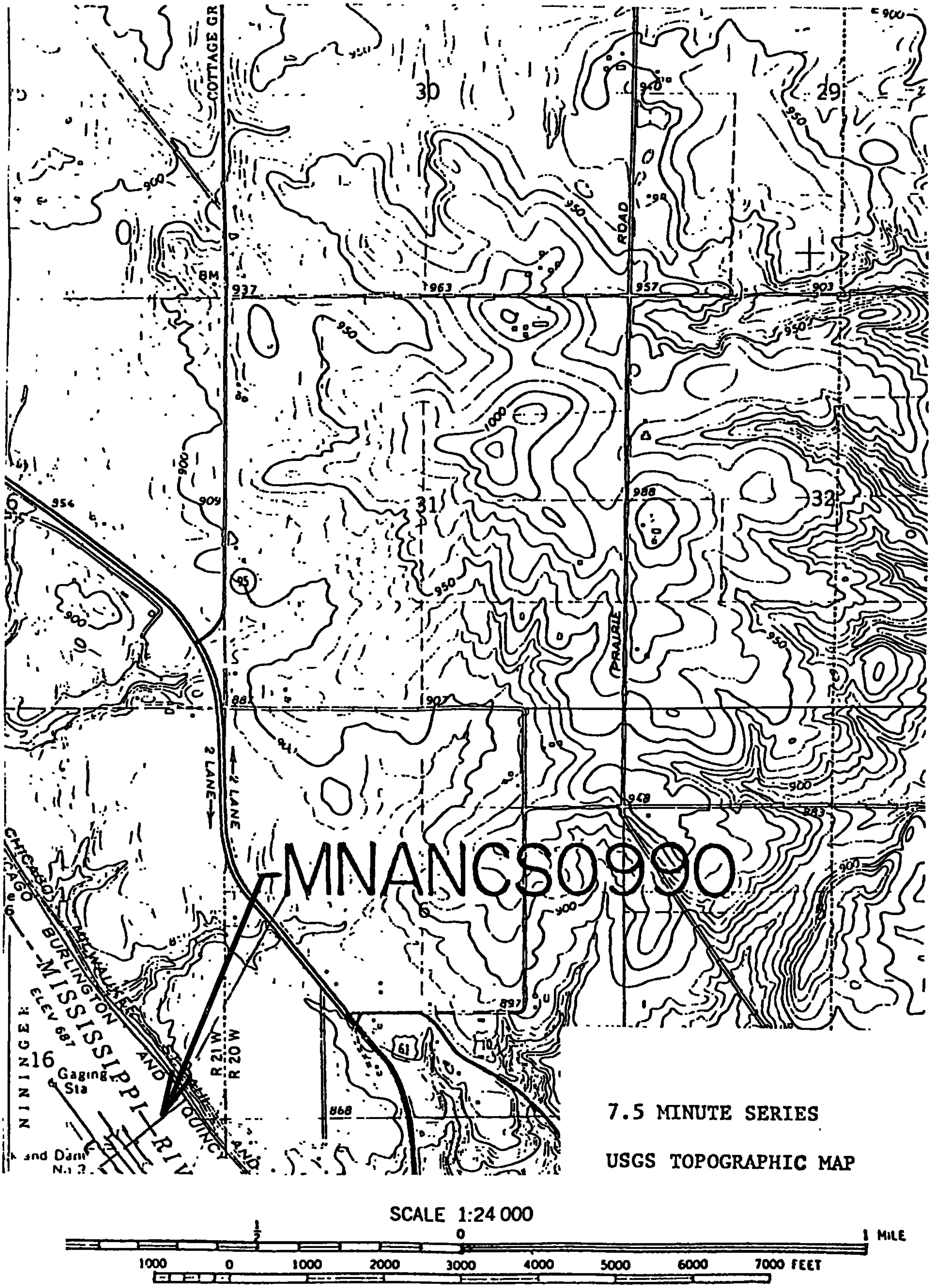
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

Lock 2

ID # MNANCS0990

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Dakota
Stream			Mississippi
Latitude			44° 45.5'
Longitude			92o 52'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft			12
Max. Storage - Acre-Ft.			240,000
Rated Discharge - C.F.S.			6,200
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	0	4,900	4,900
Average Annual Energy - MWH	0	32,700	32,700
Average Annual Plant Factor - %	0	----	76
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	20.12	----
Average Annual Cost - $	----	658,300	----
Average Annual Benefits - $	----	831,600	----
Net Benefits - $	----	173,300	----
B/C	----	1.26	----

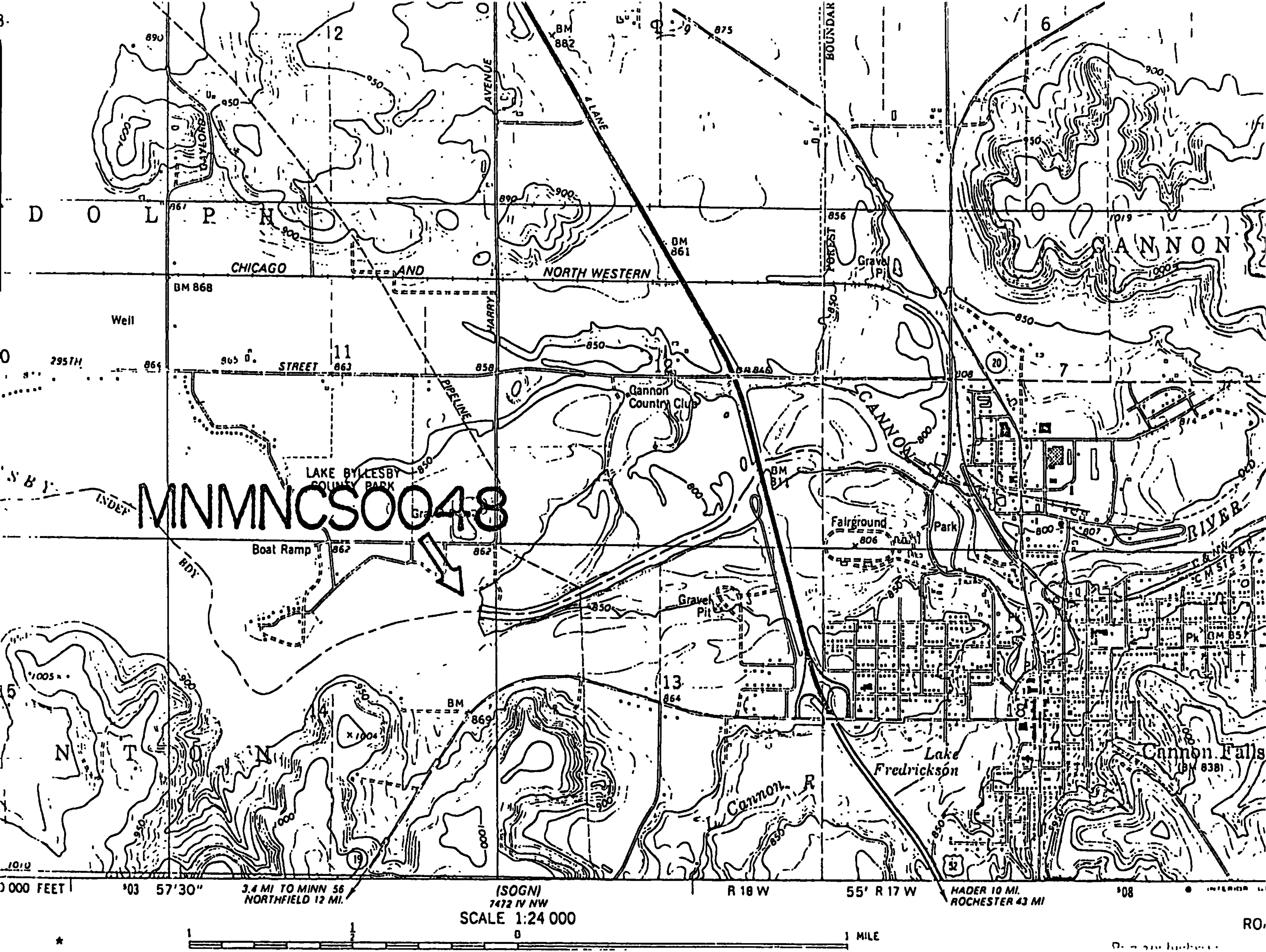

MNANCS0990
7.5 MINUTE SERIES
USGS TOPOGRAPHIC MAP
SCALE 1:24 000
1/2
0
1 MILE
1000
0
1000
2000
3000
4000
5000
6000
7000 FEET
COTTAGE GR
ROAD
PRAIRIE
2 LANE
CHICAGO BURLINGTON AND QUINCY
MILWAUKEE
MISSISSIPPI RIV
ELEV 687
Gaging Sta
R 21 W
R 20 W
30
29
31
32
6
16
61
BM
937
963
957
903
950
900
1000
988
909
954
907
948
883
897
868

PERTINENT DATA

Cannon River

ID # MNMNCS0048

ITEM			DESCRIPTION
Location			
State			Minnesota
County			Goodhue
Stream			Cannon River
Latitude			44° 30.7'
Longitude			92° 56.4'
Owner			Dakota & Goodhue County
PHYSICAL			
Net Power Head - Ft.			56
Max. Storage - Acre-Ft.			25,000
Rated Discharge - C.F.S.			1,700
Power	Existing	New Potential	Total
Installed Capacity - KW	0	6,900	6,900
Average Annual Energy - MWH	0	13,000	13,000
Average Annual Plant Factor - %	0	----	22
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	29.65	----
Average Annual Cost - $	----	381,000	----
Average Annual Benefits - $	----	587,100	----
Net Benefits - $	----	206,100	----
B/C	----	1.54	----

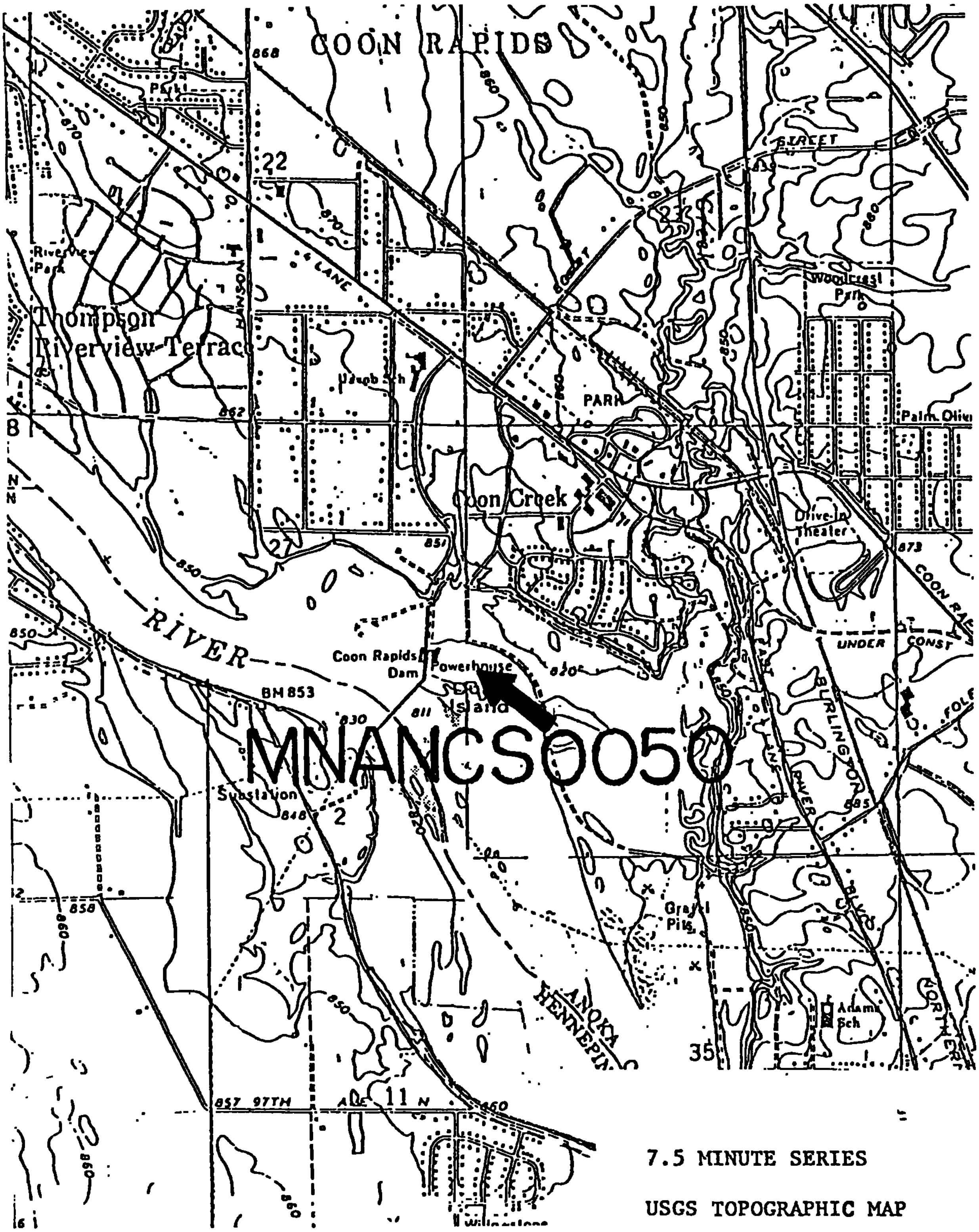

MNMNCS0048
CHICAGO AND NORTH WESTERN
295TH STREET
HARRY AVENUE
4 LANE
PIPELINE
FOREST BOUNDARY
LAKE BYLLESBY COUNTY PARK
Boat Ramp
Well
Cannon Country Club
Gravel Pit
Fairground
Park
CANNON RIVER
CANNON
Lake Fredrickson
Cannon R
Cannon Falls
BM 868
BM 861
BM 882
BM 869
3.4 MI TO MINN 56
NORTHFIELD 12 MI.
(SOGN)
7472 IV NW
R 18 W
55' R 17 W
HADER 10 MI.
ROCHESTER 43 MI
57'30"
SCALE 1:24 000
1 MILE

PERTINENT DATA

Coon Rapids

ID # MNANCS0050

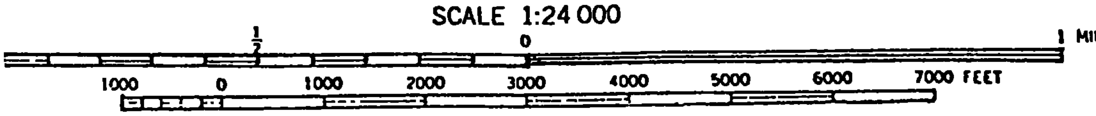
ITEM			DESCRIPTION
Location			
State			Minnesota
County			Hennepin
Stream			Mississippi
Latitude			45° 8.6'
Longitude			93° 18.6'
Owner			Hennepin County Park Reserv
PHYSICAL			
Net Power Head - Ft.			17
Max. Storage - Acre-Ft.			2,000
Rated Discharge - C.F.S.			9,500
Power	Existing	New Potential	Total
Installed Capacity - KW	0	16,200	16,200
Average Annual Energy - MWH	0	82,700	82,700
Average Annual Plant Factor - %	0	----	58
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	15.09	----
Average Annual Cost - $	----	1,247,500	----
Average Annual Benefits - $	----	2,177,700	----
Net Benefits - $	----	930,200	----
B/C	----	1.75	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

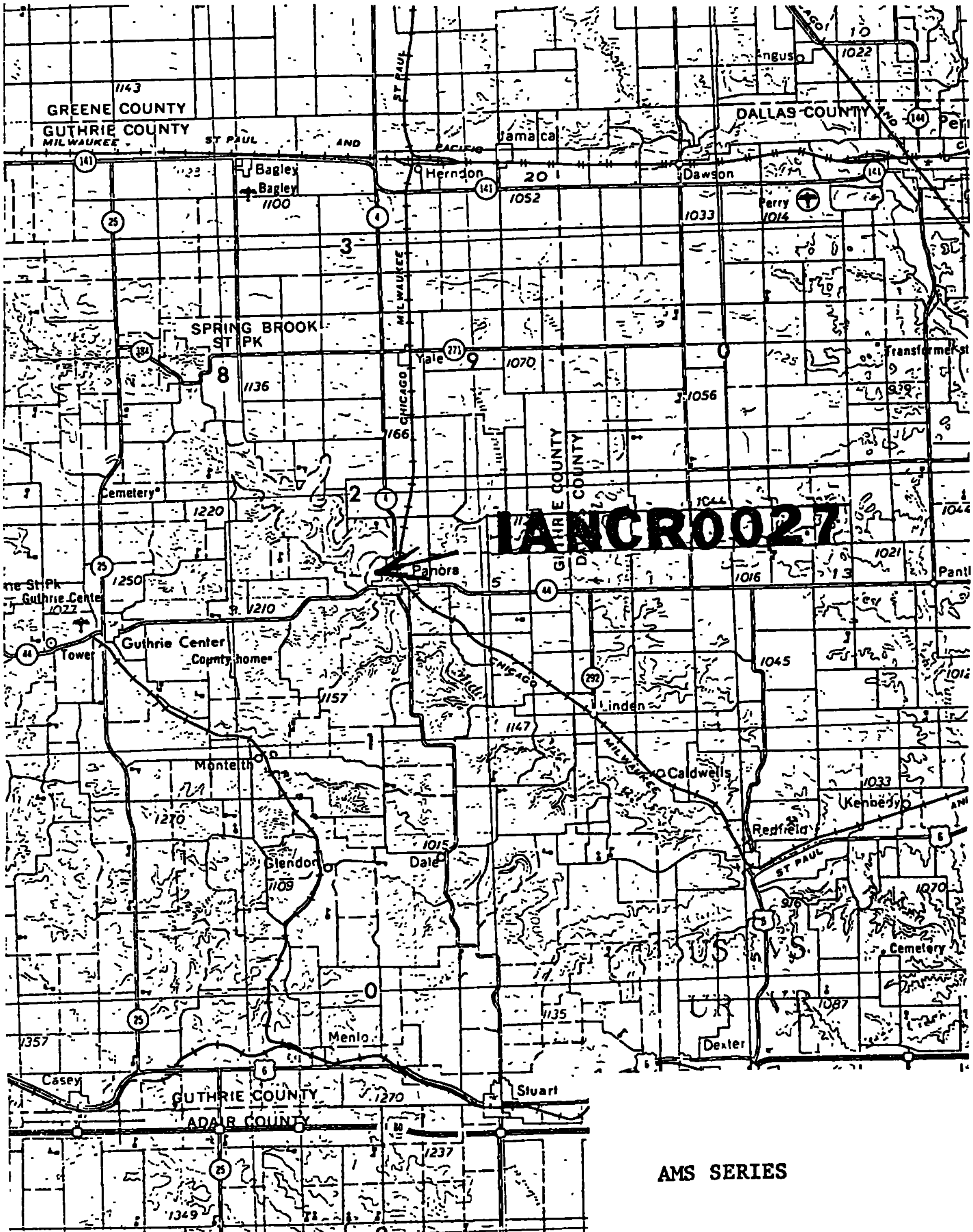


PERTINENT DATA

232 IA NO

ID # IAGNCR0027

ITEM			DESCRIPTION
Location			
State			Iowa
County			Guthrie
Stream			Middle Raccoon
Latitude			41° 41.8'
Longitude			94° 22.9'
Owner			Mid-Iowa Lakes Corp.
PHYSICAL			
Net Power Head - Ft.			58
Max. Storage - Acre-Ft.			23,700
Rated Discharge - C.F.S.			700
Power	Existing	New Potential	Total
Installed Capacity - KW	0	2,976	2,976
Average Annual Energy - MWH	0	5,625	5,625
Average Annual Plant Factor - %	0	----	21
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	42.27	----
Average Annual Cost - $	----	237,800	----
Average Annual Benefits - $	----	254,000	----
Net Benefits - $	----	16,200	----
B/C	----	1.06	----



AMS SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:250,000

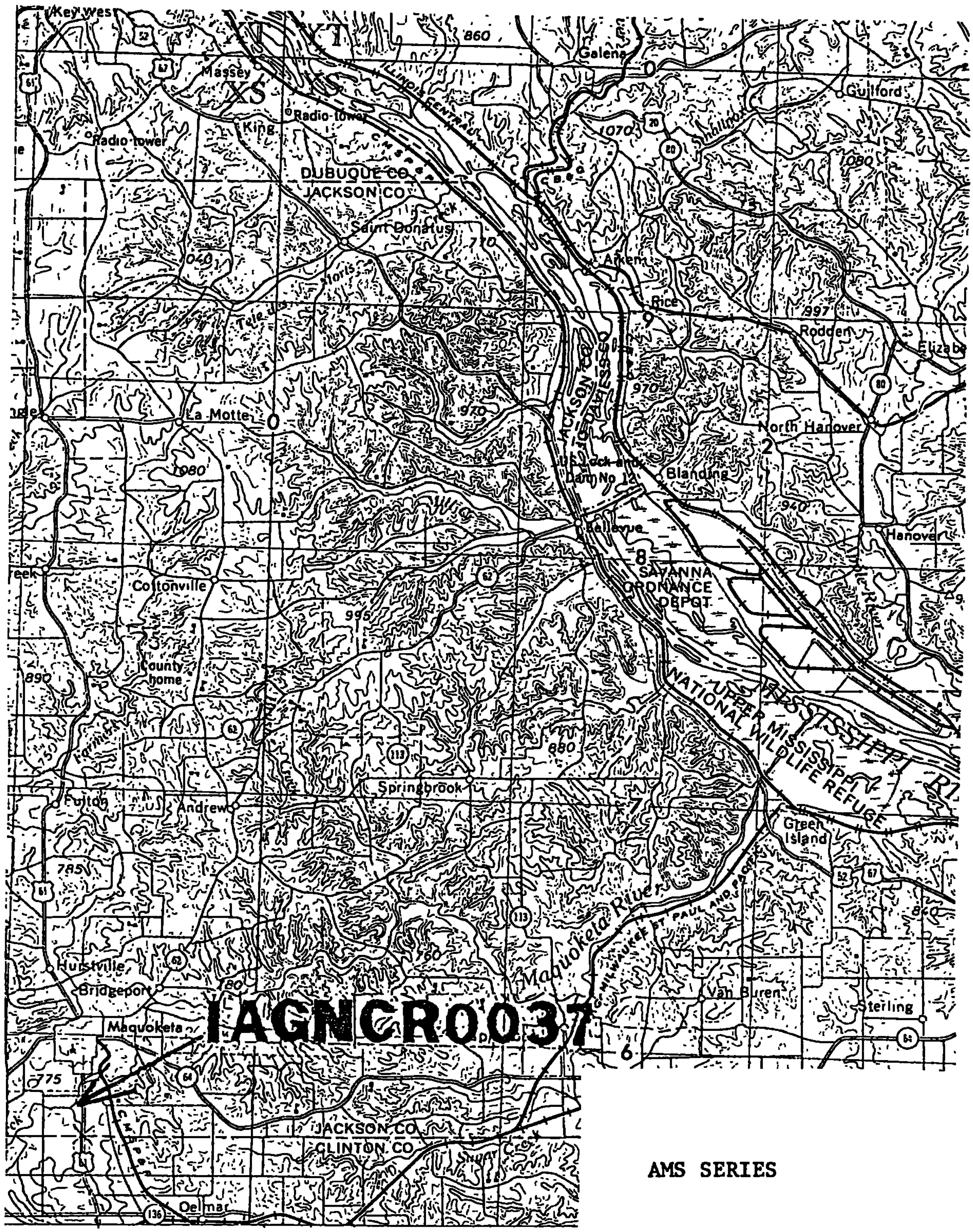
5 0 5 Statute Miles

PERTINENT DATA

719 IA NO

ID # IAGNCR0037

ITEM			DESCRIPTION
Location			
State			Iowa
County			Jackson
Stream			South Fork
Latitude			42° 4.1'
Longitude			90° 41.8'
Owner			Iowa Electric Light & Power
PHYSICAL			
Net Power Head - Ft.			25
Max. Storage - Acre-Ft.			1,200
Rated Discharge - C.F.S.			2,900
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	1,200	4,100	5,300
Average Annual Energy - MWH	5,000	8,700	13,700
Average Annual Plant Factor - %	48	----	30
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	30.19	----
Average Annual Cost - $	----	262,500	----
Average Annual Benefits - $	----	353,600	----
Net Benefits - $	----	91,100	----
B/C	----	1.35	----



AMS SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:250,000

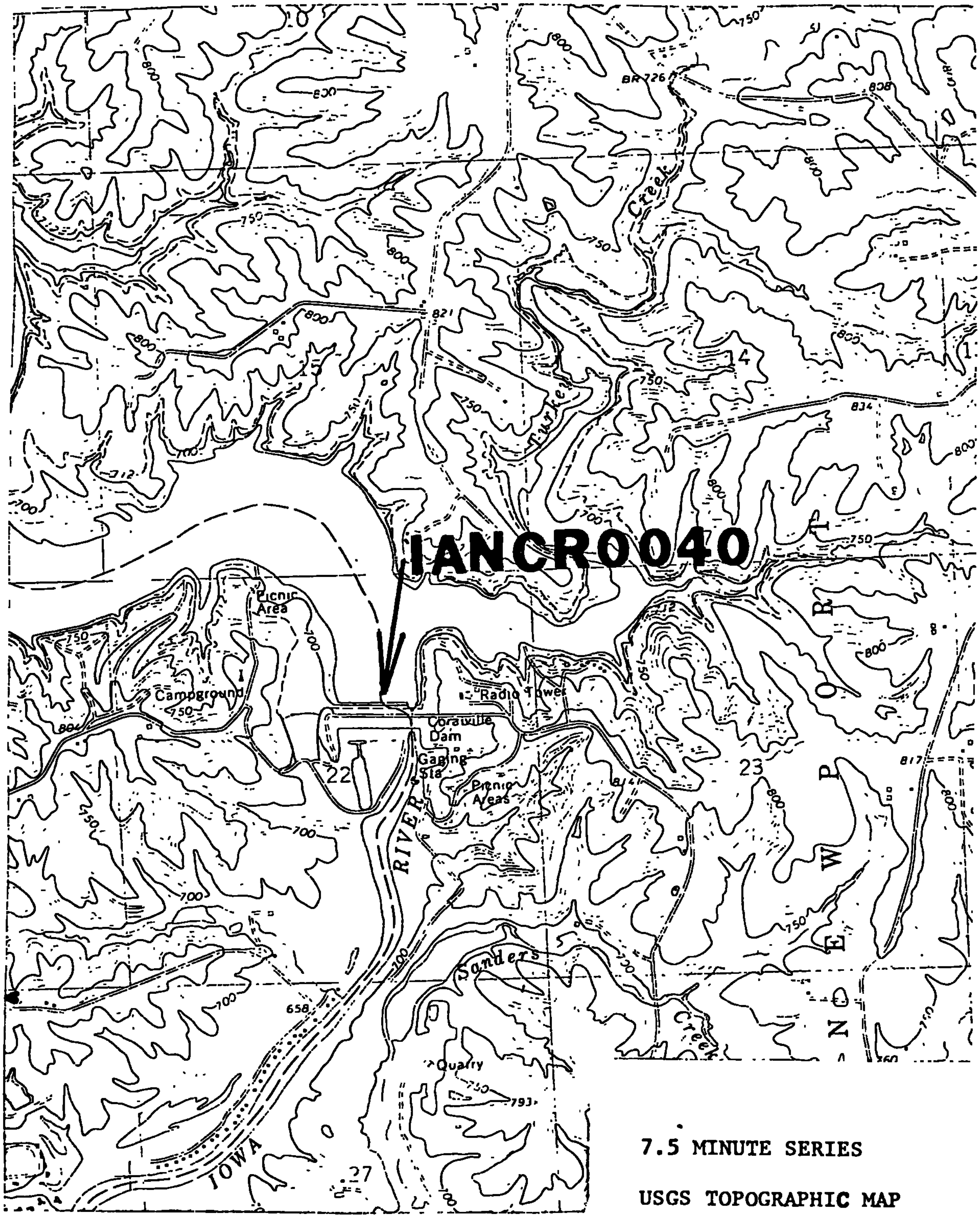
5 0 5 Statute Miles

PERTINENT DATA

Coralville

ID # IACNCR0040

ITEM			DESCRIPTION
Location			
State			Iowa
County			Johnson
Stream			Iowa River
Latitude			41° 43.3'
Longitude			91° 31.6'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			29
Max. Storage - Acre-Ft.			585,000
Rated Discharge - C.F.S.			5,600
Power	Existing	New Potential	Total
Installed Capacity - KW	0	11,600	11,600
Average Annual Energy - MWH	0	25,700	25,700
Average Annual Plant Factor - %	0	----	25
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	33.62	----
Average Annual Cost - $	----	865,100	----
Average Annual Benefits - $	----	1,071,500	----
Net Benefits - $	----	206,400	----
B/C	----	1.24	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1/2 0 1 MILE

1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

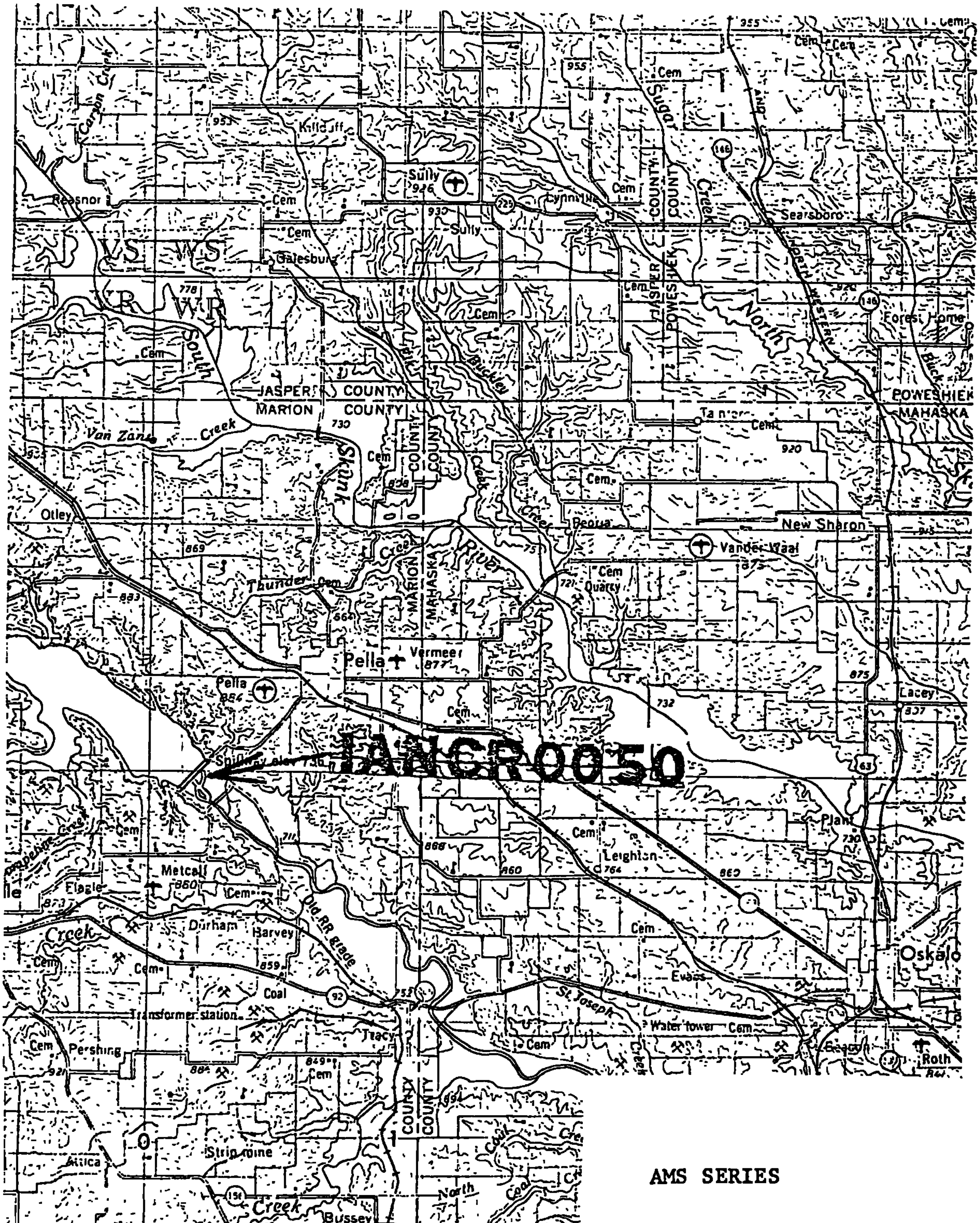
PERTINENT DATA

Red Rock

ID # IACNCR0050

ITEM			DESCRIPTION
Location			
State			Iowa
County			Marion
Stream			Des Moines
Latitude			41° 22.1'
Longitude			92.° 58.5'
Owner			Army Corps of Engineers
PHYSICAL			
Net Power Head - Ft.			44
Max. Storage - Acre-Ft.			1,830,000
Rated Discharge - C.F.S.			18,000

Power	Existing	New Potential	Total
Installed Capacity - KW	0	57,900	57,900
Average Annual Energy - MWH	0	116,500	116,500
Average Annual Plant Factor - %	0	----	23
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	31.60	----
Average Annual Cost - $	----	3,682,100	----
Average Annual Benefits - $	----	5,101,200	----
Net Benefits - $	----	1,419,100	----
B/C	----	1.39	----



AMS SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:250,000

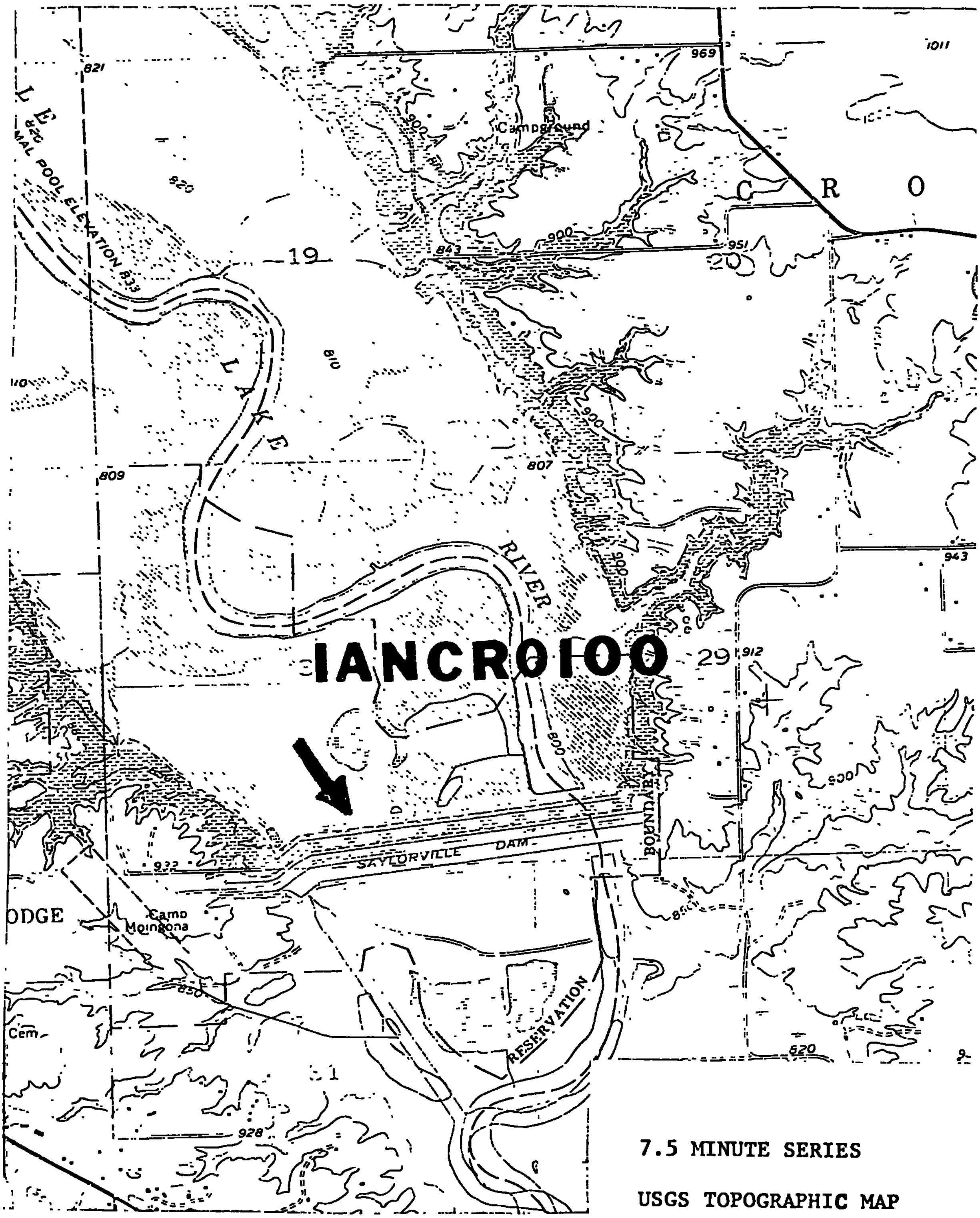
5 0 5 Statute Miles

PERTINENT DATA

Saylorville

ID # IACNCR0100

ITEM			DESCRIPTION
Location			
State			Iowa
County			Rusk
Stream			Iowa River
Latitude			41° 38.0'
Longitude			93° 47.0'
Owner			Lake Superior District Power
PHYSICAL			
Net Power Head - Ft.			42
Max. Storage - Acre-Ft.			676,000
Rated Discharge - C.F.S.			5,600
Power	**Existing**	**New Potential**	**Total**
Installed Capacity - KW	0	17,300	17,300
Average Annual Energy - MWH	0	44,300	44,300
Average Annual Plant Factor - %	0	----	29
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	21.71	----
Average Annual Cost - $	----	962,100	----
Average Annual Benefits - $	----	1,657,500	----
Net Benefits - $	----	695,400	----
B/C	----	1.72	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000

1/2 0 1 MILE

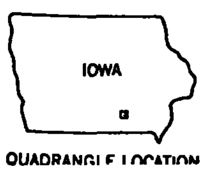
1000 0 1000 2000 3000 4000 5000 6000 7000 FEET

PERTINENT DATA

733 Iowa

ID # IAGNCR0062

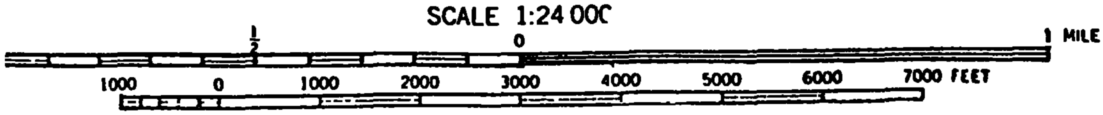
ITEM			DESCRIPTION
Location			
State			Iowa
County			Wapello
Stream			Des Moines
Latitude			41° 0.9'
Longitude			92° 24.8'
Owner			City of Ottumwa
PHYSICAL			
Net Power Head - Ft.			15
Max. Storage - Acre-Ft.			4,500
Rated Discharge - C.F.S.			4,100
Power	Existing	New Potential	Total
Installed Capacity - KW	3,000	1,500	4,500
Average Annual Energy - MWH	11,000	11,800	22,800
Average Annual Plant Factor - %	42	----	.58
Costs for New Potential			
Annual Cost of Energy - $/MWH	----	8.94	----
Average Annual Cost - $	----	105,500	----
Average Annual Benefits - $	----	215,200	----
Net Benefits - $	----	109,700	----
B/C	----	2.04	----



7.5 MINUTE SERIES

USGS TOPOGRAPHIC MAP

SCALE 1:24 000



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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.

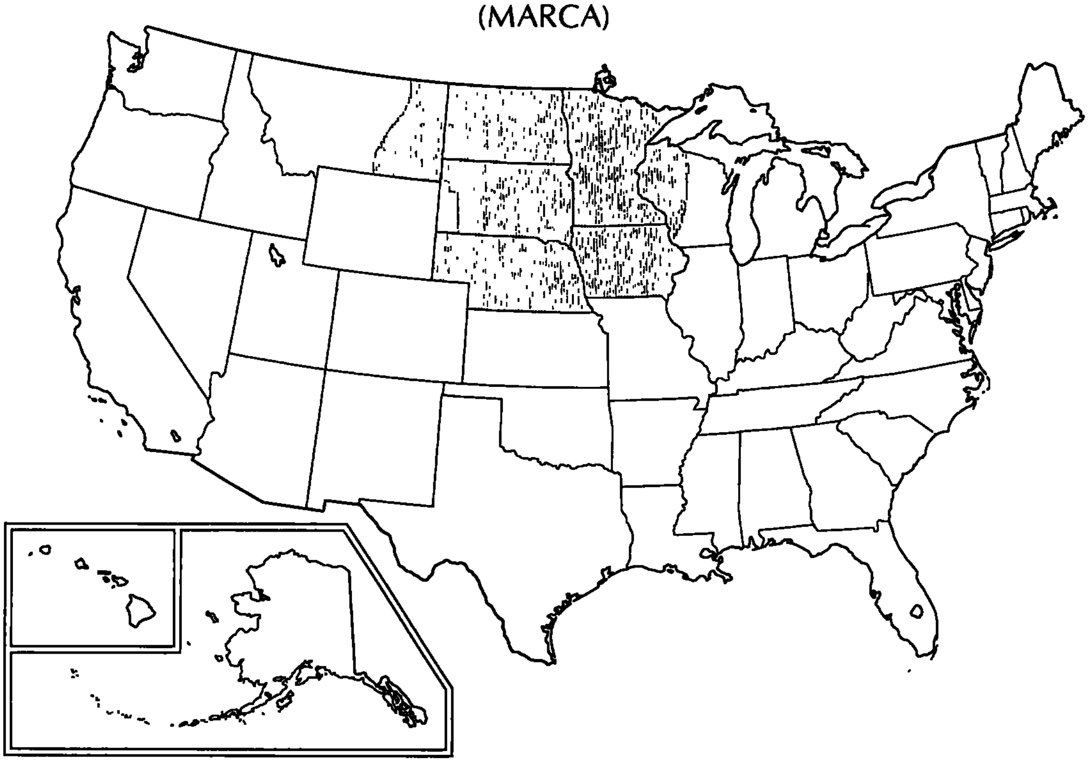
NATIONAL HYDROELECTRIC POWER
RESOURCES STUDY

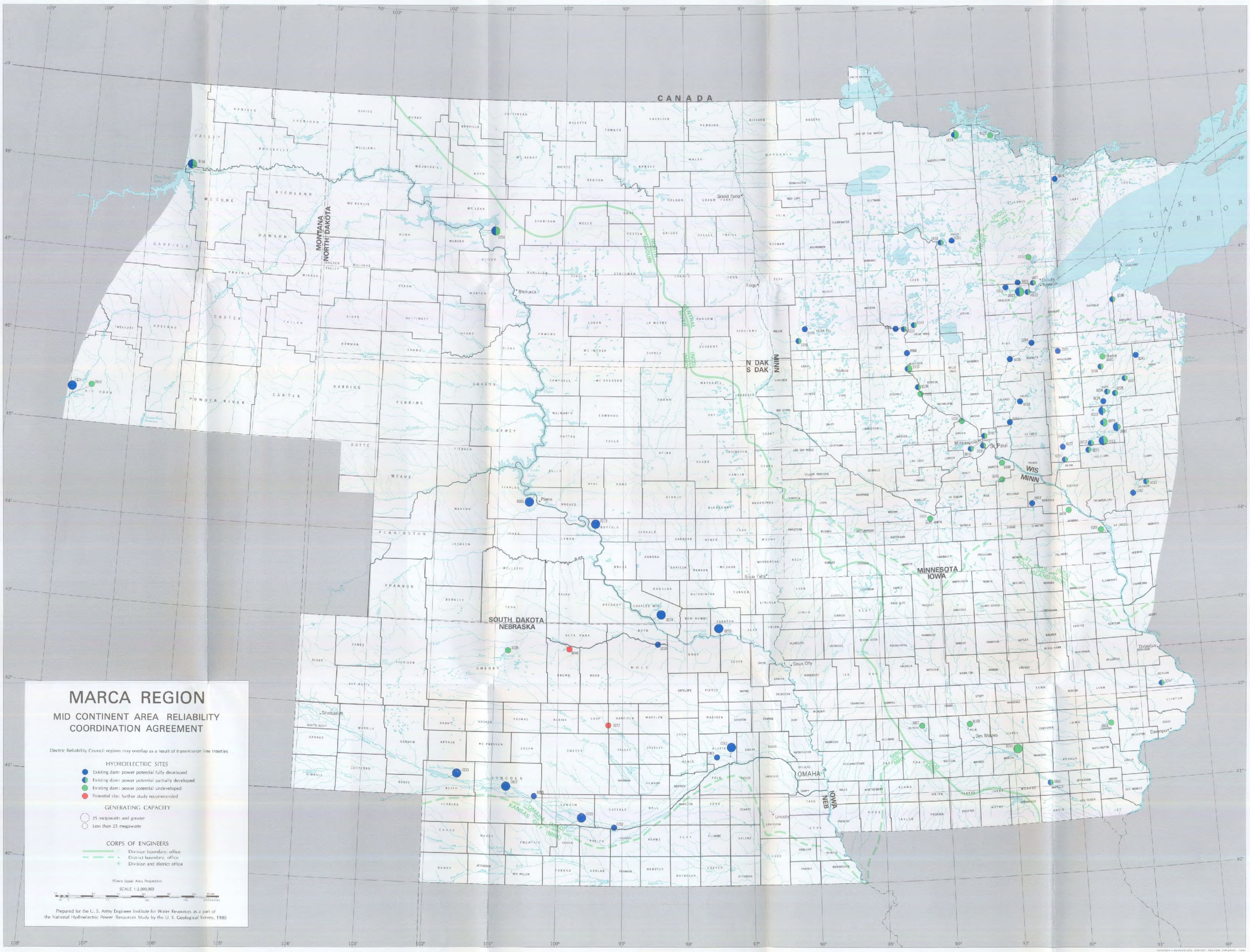
INDEX TO NATIONAL ELECTRIC RELIABILITY COUNCIL REGIONS

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
WSCC
MARCA
MAIN
ECAR
NPCC
MAAC
SWPP
SERC
ERCOT
ECAR
NORTH PACIFIC
SOUTH PACIFIC
MISSOURI RIVER
NORTH CENTRAL
OHIO RIVER
NEW ENGLAND
SOUTHWESTERN
LOWER MISSISSIPPI VALLEY
SOUTH ATLANTIC
PACIFIC OCEAN
ATLANTIC OCEAN
LAKE SUPERIOR
LAKE MICHIGAN
LAKE HURON
LAKE ERIE
LAKE ONTARIO
PACIFIC OCEAN
Principal islands of HAWAII
ALASKA
NORTH PACIFIC
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

NATIONAL HYDROELECTRIC POWER RESOURCES STUDY

MID CONTINENT AREA RELIABILITY COORDINATION AGREEMENT (MARCA)




CANADA
MONTANA
NORTH DAKOTA
N DAK
S DAK
MINN
SOUTH DAKOTA
NEBRASKA
MINNESOTA
IOWA
WIS
MINN
IOWA
NEB
LAKE SUPERIOR
Bismarck
Pierre
St. Paul
Sioux City
OMAHA
Des Moines
Duluth
MARCA REGION
MID CONTINENT AREA RELIABILITY
COORDINATION AGREEMENT
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