Northern States Power Company

414 Nicollet Mall
Minneapolis, Minnesota 55401-1927
Telephone (612) 330-5500

April 16, 1996

10 CFR 50.71(b)

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

PRAIRIE ISLAND NUCLEAR GENERATING PLANT
Docket No. 50-282 License No. DPR-40
50-306 DPR-60

Submittal of 1995 Annual Report Including the Certified Financial Statements

In accordance with 10 CFR 50.71(b) and Item No. 70 in Regulatory Guide 10.1, enclosed are ten (10) copies of our 1995 Annual Report, including the certified financial statements.

If you have any questions with regard to this information, please call Scott L. Weatherby at 612-330-7643 or Mel Opstad at 612-295-1653.

Sincerely,

Melford T. Opstad

for Roger O. Anderson
Director,
Licensing & Management Issues

Enclosures

c: w/enclosure
Regional Administrator-III, NRC
Monticello NRR Project Manager, NRC
Monticello Resident Inspector, NRC
Prairie Island NRR Project Manager, NRC
Prairie Island Resident Inspector, NRC

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State of Minnesota, Attn: Kris Sanda
J E Silberg
S L Weatherby

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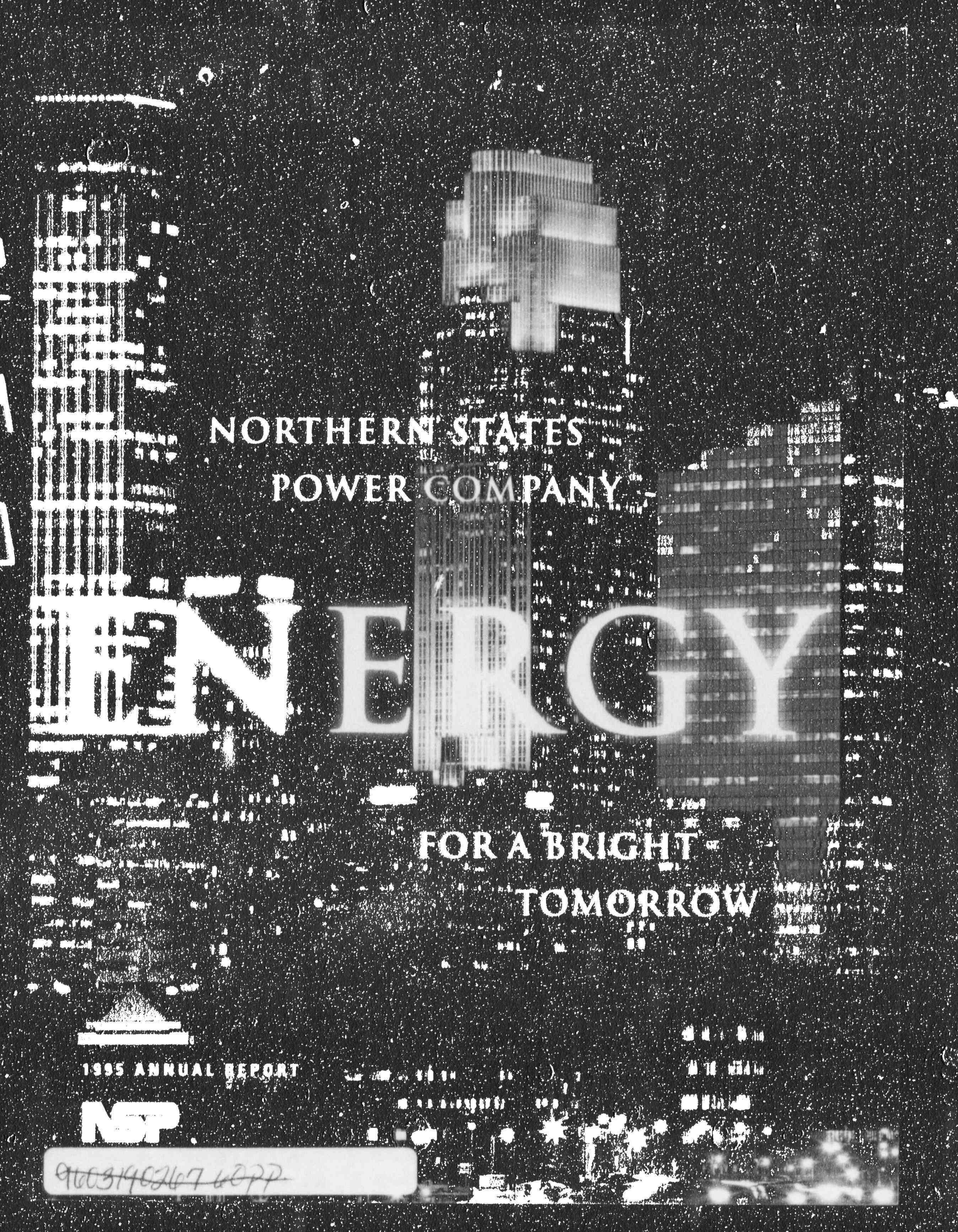


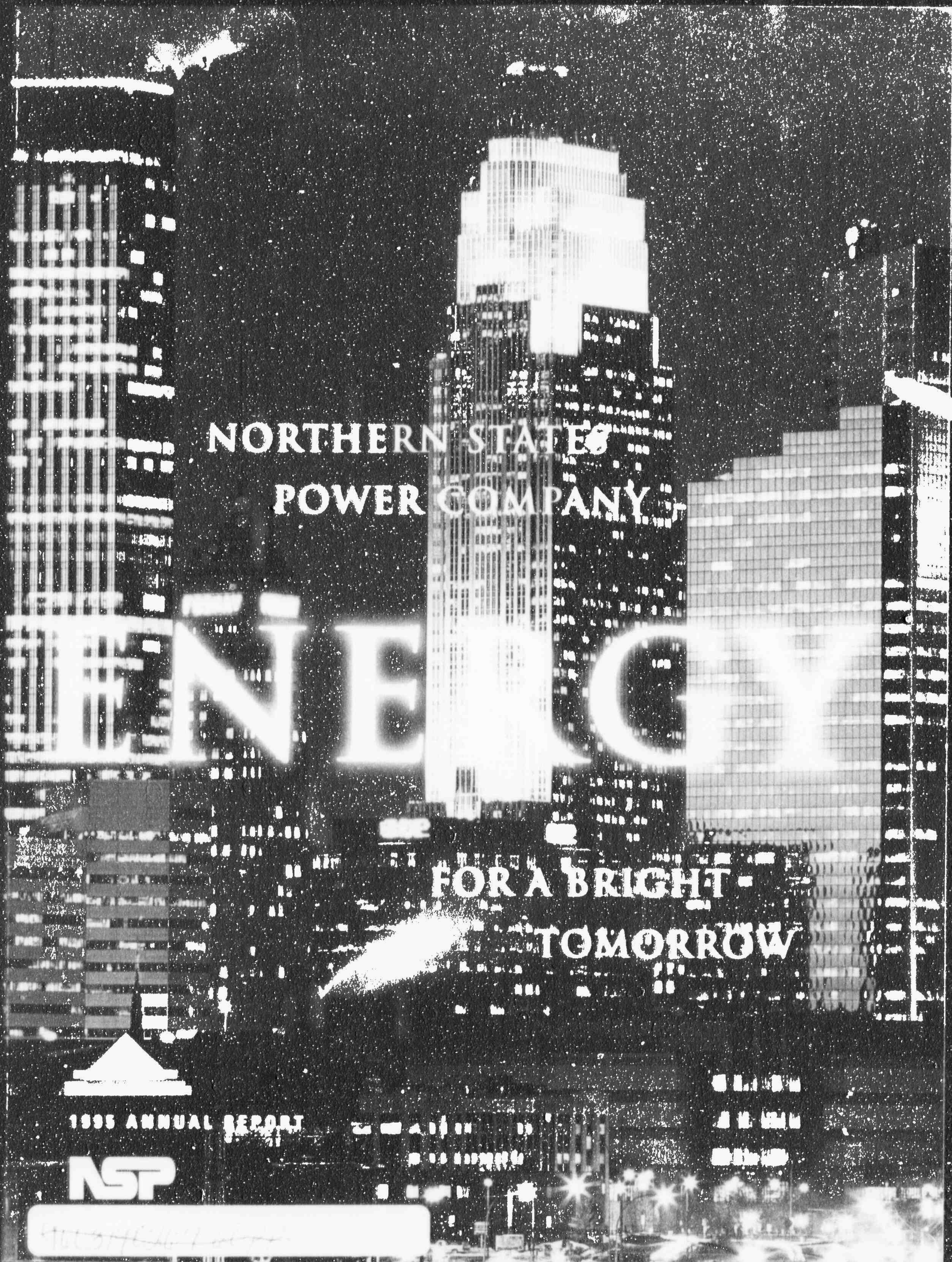
NORTHERN STATES POWER COMPANY

ENERGY

FOR A BRIGHT TOMORROW

1995 ANNUAL REPORT

NSP



NORTHERN STATES POWER COMPANY

ENERGY

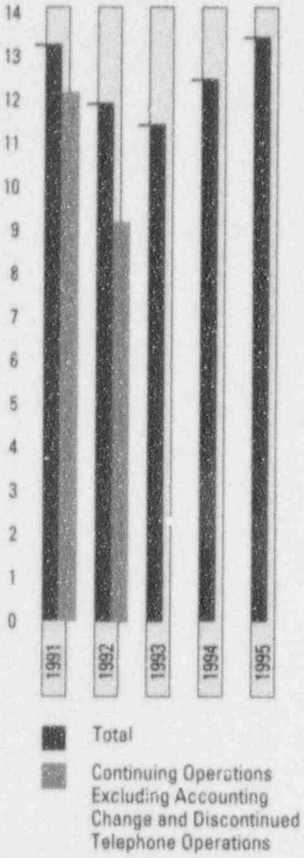
FOR A BRIGHT TOMORROW

1995 ANNUAL REPORT

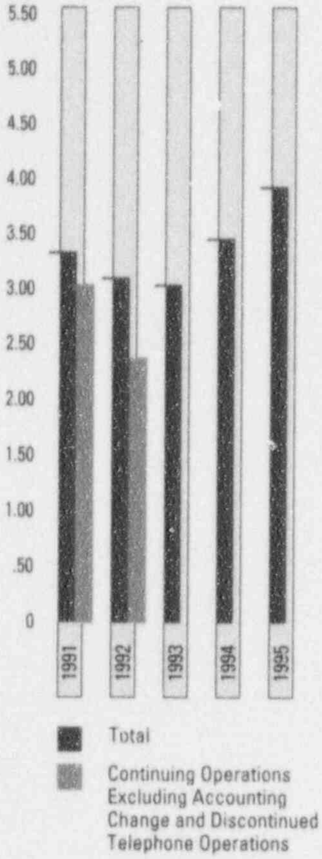
NSP

FINANCIAL SUMMARY

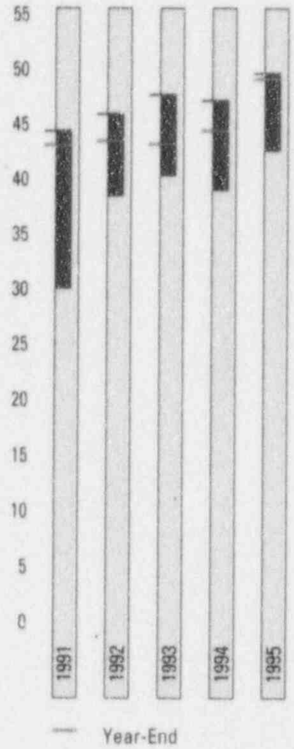
Return on Common Equity
Percent



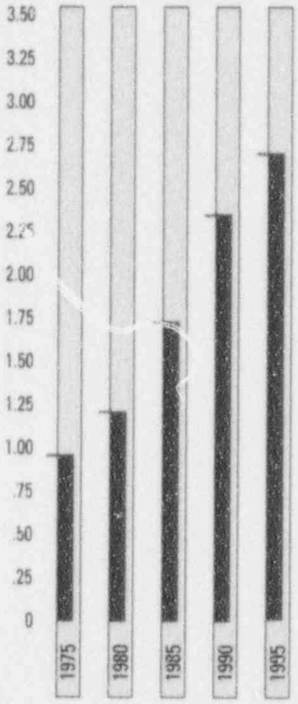
Earnings Per Share
Dollars Per Share



Common Stock Price Range
Dollars Per Share



21 Years of Dividend Growth
Dollars Per Share

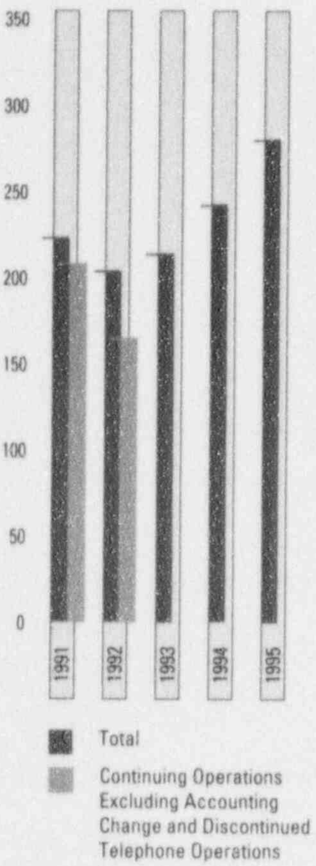


Financial Highlights

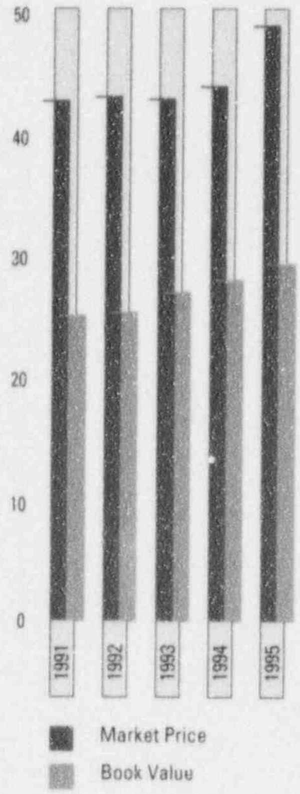
	Year ended Dec. 31		
	1995	1994	% Change
Earnings per share	**$3.91**	$3.46	13.0%
Dividends declared per share	**$2.685**	$2.625	2.3%
Utility operating revenues (millions)	**$2,568.6**	$2,486.5	3.3%
Net income (millions)	**$275.8**	$243.5	13.3%
Return on common equity	**13.4%**	12.4%	
Assets (millions)	**$6,228.6**	$5,949.7	4.6%
Customers (thousands)	**1,821.4**	1,786.4	2.0%
Peak electric demand (megawatts)	**7,519**	7,101	5.9%
Retail electric energy sales (millions of kilowatt hours)	**34,500**	33,096	4.2%
Benefit employees	**6,829**	7,032	(2.9%)

CONTENTS

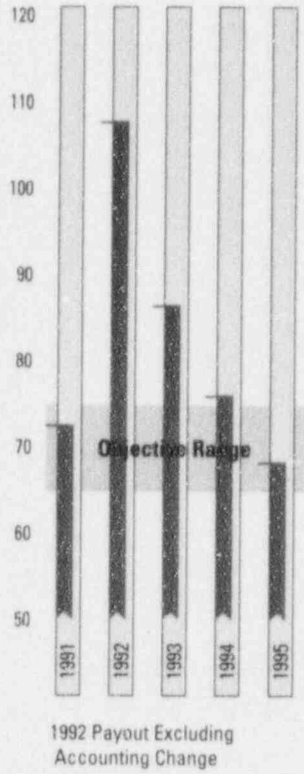
Net Income
Dollars in Millions



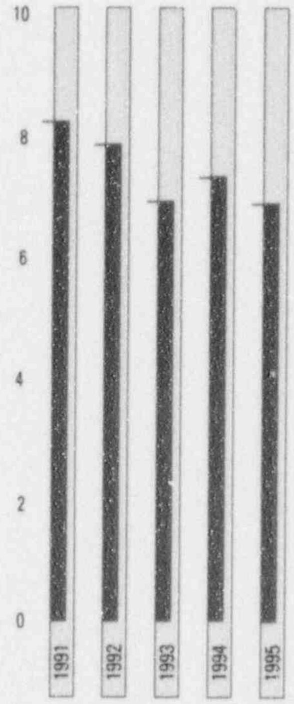
Market Price and Book Value at Year-End
Dollars Per Share



Dividend Payout Ratio
Percent of Earnings



Average Cost of Long-Term Debt
Percent



Company Description

Northern States Power Company (NSP), headquartered in Minneapolis, Minnesota, is a major U.S. utility with growing domestic and overseas non-regulated energy ventures. NSP and its wholly owned subsidiary, Northern States Power Company-Wisconsin, operate generation, transmission and distribution facilities providing electricity to about 1.4 million customers in Minnesota, Wisconsin, North Dakota, South Dakota and Michigan. The two companies also distribute natural gas to more than [illegible]0,000 customers in Minnesota, Wisconsin, North Dakota and Michigan, and provide a variety of energy-related services throughout their service areas.

NRG Energy, Inc., a wholly owned subsidiary, operates and has interests in independent, non-regulated power and energy businesses in the United States and other countries, with major projects in Germany and Australia.

Viking Gas Transmission Company, a wholly owned subsidiary, owns and operates a 500-mile interstate natural gas pipeline providing gas transportation services to customers in the Upper Midwest from connections with four major pipelines in the United States and Canada.

Cenergy, Inc., another wholly owned subsidiary, became Cenerprise, Inc. on January 1, 1996. The company markets natural gas, electricity and energy-related services throughout the United States.

Letter to Shareholders

James J. Howard
Chairman of the Board, President and Chief Executive Officer

Nineteen ninety-five was another good year for your company. Our financial performance was strong, our subsidiaries continued to seek opportunities to grow and we took significant action to help ensure success in the years ahead.

The single most important event in 1995 was our agreement to merge with Wisconsin Energy Corporation to form Primergy Corporation. We announced the plan on May 1, and shareholders of both companies gave their overwhelming approval in September. Now we are pursuing approvals from the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Department of Justice, the Federal Trade Commission, the Nuclear Regulatory Commission and public service commissions in Minnesota, Wisconsin, North Dakota and Michigan. We remain optimistic that the merger will be completed by January 1, 1997.

Wisconsin Energy is an electric and natural gas utility headquartered in Milwaukee that serves much of eastern Wisconsin and portions of the Upper Peninsula of Michigan. Like NSP, Wisconsin Energy has low prices, is financially sound, has commendable operating records and is committed to environmental protection, safety and community involvement. NSP and Wisconsin Energy fit well together.

We are enthusiastic about the merger because our industry is at the crossroads of change. Through industry restructuring at the state and federal levels, competition will continue to increase and more open electric markets will enable commercial, industrial and even residential customers to choose their energy suppliers. We want them to choose Primergy. We believe the merger will help us succeed in the new marketplace and help your company continue to grow and prosper. By ensuring continued competitive prices, high-quality services and commitment to customer satisfaction, Primergy will help communities attract new business, add jobs and strengthen the economy in our combined service area.

NSP and Wisconsin Energy look forward to

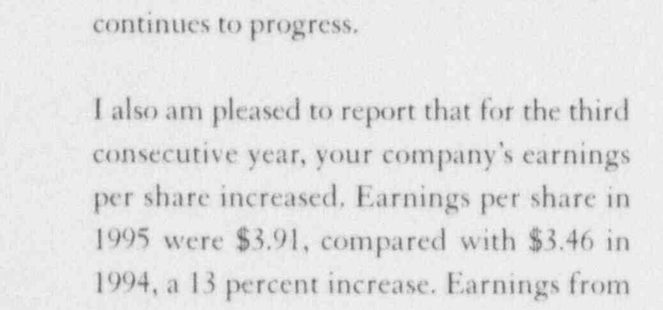
competition, and we intend to be ready for it in all respects. We have the vision, the technologies and the expertise. We have employees who can execute our plans in the empowered work environment we are creating for them.

NSP and Wisconsin Energy are analyzing carefully the best business and operating practices of both companies and other industry leaders to help shape Primergy for a dynamic future. The strong leadership and entrepreneurial spirit of our employees will guide our new company. Primergy, to be headquartered in Minneapolis, will be positioned to build long-term value for our shareholders, while enhancing customer service and system reliability.

We will keep you informed as the merger continues to progress.

I also am pleased to report that for the third consecutive year, your company's earnings per share increased. Earnings per share in 1995 were $3.91, compared with $3.46 in 1994, a 13 percent increase. Earnings from ongoing operations, excluding non-recurring transactions, were $3.69 per share, compared with $3.45 in 1994, a 7 percent increase. Net income for the year ended December 31, 1995, was $275.8 million, compared with $243.5 million in 1994.

Primergy Service Territory



The new **Primergy Corporation's** electric and natural gas service area includes portions of Minnesota, Wisconsin, Michigan's Upper Peninsula, North Dakota and South Dakota.

Higher electric and natural gas sales and reduced operating and maintenance costs contributed to strong earnings in 1995. Total retail electric sales increased 4.2 percent, in part due to a 1.3 percent increase in customer accounts. Warmer-than-normal summer weather also contributed to higher demand for electricity. Total gas sales increased 9.8 percent, and customer accounts increased 4.1 percent. Higher costs for depreciation, taxes and interest expenses partially offset the increases.

We are well-positioned to reach our objective of long-term earnings growth of 5 percent per year, on average, from ongoing operations.

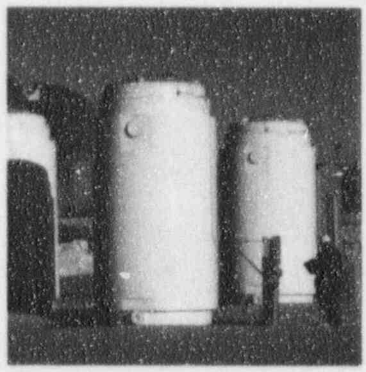
In 1995, our non-regulated businesses, including: NRG Energy, Inc.; Cenergy, Inc., which became Cenerprise, Inc. on January 1, 1996; and Eloigne Company continued to seek opportunities to grow. NSP's non-regulated businesses contributed 50 cents per share in 1995, compared with 49 cents per share in 1994.

For the 21st consecutive year, your dividend increased to an annual rate of $2.70 per share, compared with $2.64 in 1994. NSP's common stock closed the year at $49.125, up from the 1994 close of $44.

In addition to strong financial performance, business expansion and preparation for the future through our proposed merger, your company also made progress in other areas.

In 1995, NSP began storing used nuclear fuel in reinforced steel containers at an outdoor facility adjacent to our Prairie Island nuclear power plant in Red Wing, Minnesota. By the end of the year, three 122-ton loaded casks were moved to the storage area.

In 1994, the Minnesota Legislature authorized NSP to phase in the use of 17 containers for temporary fuel storage if our company meets several requirements. They include finding an alternative storage site in Goodhue County, away from Prairie Island, and the development or purchase of 425 megawatts of wind-generated and 125 megawatts of biomass-generated electricity by 2002. We continue to make progress in all three areas.



In 1995, NSP began to store used nuclear fuel in reinforced steel containers adjacent to the company's **Prairie Island** plant. NSP continues to work at the state and federal government levels to resolve the issue on a permanent basis. Storage at the plant site is temporary.

Members of the Prairie Island Indian Community requested that we provide funding and land in exchange for their support of new legislation ending the requirement for an alternative storage site. One legislative committee approved the new proposal. However, it has not advanced in a second committee. We will continue to work with members of the Indian community and the Legislature to resolve issues of mutual interest.

Our plan to temporarily store used fuel on or adjacent to Mescalero Apache land in New Mexico also moved forward in 1995. NSP and the Mescalero Apache tribe are leading a group of more than 20 utilities participating in the project.

In early 1996, the Mescalero project consortium plans to select a site for the facility and determine the storage technology to be used. By the end of the year, the group plans to submit a project license application to the Nuclear Regulatory Commission. Our objective is to have the temporary storage facility operating by 2002.

The federal government is responsible for establishing a permanent nuclear waste repository. As chairman of the Nuclear Energy Institute, I have encouraged nuclear utility companies and other groups to work with government officials at the state and federal levels to resolve the nuclear storage issue. A successful resolution is vital to our company, our industry and our country. Nuclear energy provides about 30 percent of the electricity our customers use. They require a variety of reliable energy sources, including nuclear power, to enhance economic and environmental progress. As shareholders and citizens, you can be proud that your company has taken a leadership position on these important issues.

Economic development is a priority for NSP's service area. In 1995, your company participated in 29 economic development projects in Minnesota that helped create or retain 3,900 jobs and are expected to generate an estimated $6.2 million in annual revenues for NSP. The projects include a new manufacturing facility Seagate Technology, Inc. is building in Bloomington, Minnesota.

In Eau Claire, Wisconsin, Hutchinson Technology Inc. built a manufacturing plant in Gateway West Industrial Park, a partnership between NSP and the city of Eau Claire. A second plant is scheduled to be built in 1996 and operating in 1997. Total employment for the two plants is estimated at 2,300. In South Dakota, NSP's commitment to economic development in 1995 contributed more than $2.2 million in revenue for NSP and an estimated 2,900 jobs in Sioux Falls alone. In North Dakota, NSP helped attract First Bank, Cargill and Marvin Windows facilities, and assisted the state campaign supporting retention of two U.S. Air Force bases in Minot and Grand Forks.

Hutchinson Technology Inc. makes suspension assemblies for computer disk drives and currently supplies about 70 percent of the market.

We also are proud of our efforts to assist people in our communities. Our corporate contributions program, which primarily focuses on supporting disadvantaged people, provided $4.5 million in direct grants throughout our service area. Other efforts, including nearly 15,000 hours of volunteer service and a successful United Way campaign, also are significant.

I believe being a good corporate citizen makes good business sense. Not only does the effort help people in need, it also will help us retain and attract customers in the much more competitive environment we face.

Our overall progress in 1995 was gratifying. As we move ahead with the merger, we will continue to focus on improving financial results, promoting profitable growth in our core electric and natural gas businesses and subsidiaries, and operating our power plants and other facilities safely, efficiently and with respect for the environment. We will continue to serve our customers well, and we will help our employees adapt to changes in our industry. Our success today is a key to providing energy for a bright tomorrow.

On behalf of our Board of Directors, officer team and all of our employees, I thank you sincerely for your confidence and support. We will continue to strive to earn it each and every day in the years ahead.

Sincerely,

James J. Howard

James J. Howard
Chairman of the Board,
President and
Chief Executive Officer
February 19, 1996

FUTURE.

Advanced information technology in KCP's new control center enables the company to work more effectively with customers, which is vital in a competitive environment. Shift leaders in the control center are designated customer advocates — responsible for communicating with key commercial and industrial customers about outages and service restoration.

FUTURE

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ENERGY FOR A BRIGHT TOMORROW

To ensure a bright tomorrow for our shareholders, customers and employees, NSP is meeting the challenges of a rapidly changing marketplace with aggressive strategies for the future. Our proposal to merge with Wisconsin Energy Corporation to form Primergy Corporation was the most significant of several far-reaching decisions that will enhance our ability to grow and thrive in a competitive environment. In addition, we are actively pursuing opportunities for profitable growth through our non-regulated subsidiaries, and are investing in new technologies to improve productivity and customer service.

NSP's **Chisago** substation is one of several in the United States and Canada newly equipped with technologically advanced electrical devices as part of a project upgrading NSP's 500-kilovolt transmission line to Canada.

Equally important is our reliance on the fundamental good practices that continue to contribute to our success: environmental protection, safety, cost control, workforce effectiveness, and community involvement.

NSP recognizes that customers are driving the competitive changes occurring in the electric industry. We support competition in both the wholesale and retail electric markets because it allows customers to choose their energy supplier, lowers prices and increases operating efficiency.

Our customers are key to our decision-making. In March 1996, after more than two years of planning and development, we will install a new customer service system (CSS) that employs the latest information technology. CSS enables us to deal proactively and much more effectively with customer needs, particularly the billing requirements of large customers. With the system's ease of use, we expect significant productivity gains as we provide customers with faster and more meaningful information.

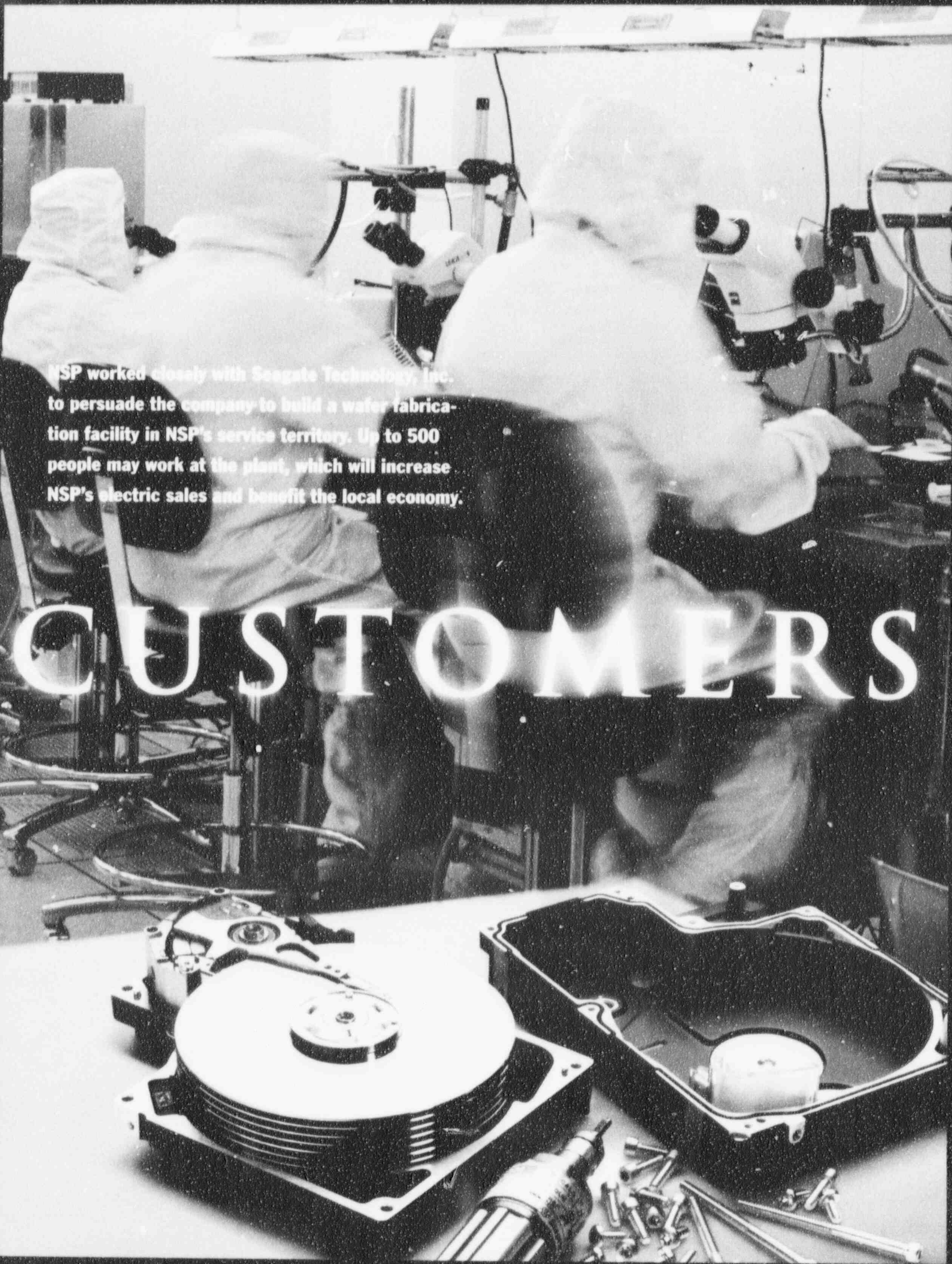
Improved customer service and productivity also were important factors in upgrading and redesigning NSP's control center, which began operating in April 1995. The center, featuring advanced information technology, consolidates the management of generation, transmission and distribution operations in one location.

Advances in transmission line technology contributed to the success of a three-year project to upgrade NSP's 500-kilovolt transmission line to Canada. The project increased the capacity of the line by about 45 percent, eliminating the need to construct hundreds of miles of new transmission lines while enabling NSP to fulfill its electricity exchange agreements with the Manitoba Hydro-Electric Board.

Technology allows us to achieve marked improvements in customer service, but

NSP worked closely with Seagate Technology, Inc. to persuade the company to build a wafer fabrication facility in NSP's service territory. Up to 500 people may work at the plant, which will increase NSP's electric sales and benefit the local economy.

CUSTOMERS



NSP worked closely with Seagate Technology, Inc. to persuade the company to build a wafer fabrication facility in NSP's service territory. Up to 500 people may work at the plant, which will increase NSP's electric sales and benefit the local economy.

CUSTOMERS

there is no substitute for developing a personal relationship with customers. When Seagate Technology, Inc., the world's largest volume manufacturer of magnetic recording heads, was evaluating locations for a third wafer fabrication facility, NSP formed a consultative account team representing several areas of the company to help attract Seagate's new facility.

Seagate decided to locate the plant in Bloomington, Minnesota, part of NSP's service territory and adjacent to an existing Seagate facility. Because electric reliability is essential to Seagate's operations, NSP accelerated its scheduled upgrade of the Nine Mile Creek substation.

Honeywell, Inc., one of NSP's largest electric customers, has received more than $1 million in rebates for energy-efficiency improvements and the installation of a cool storage system. NSP key account executive Albert Joe (right) worked with Honeywell's Ben Cyr (left) on lighting improvements.

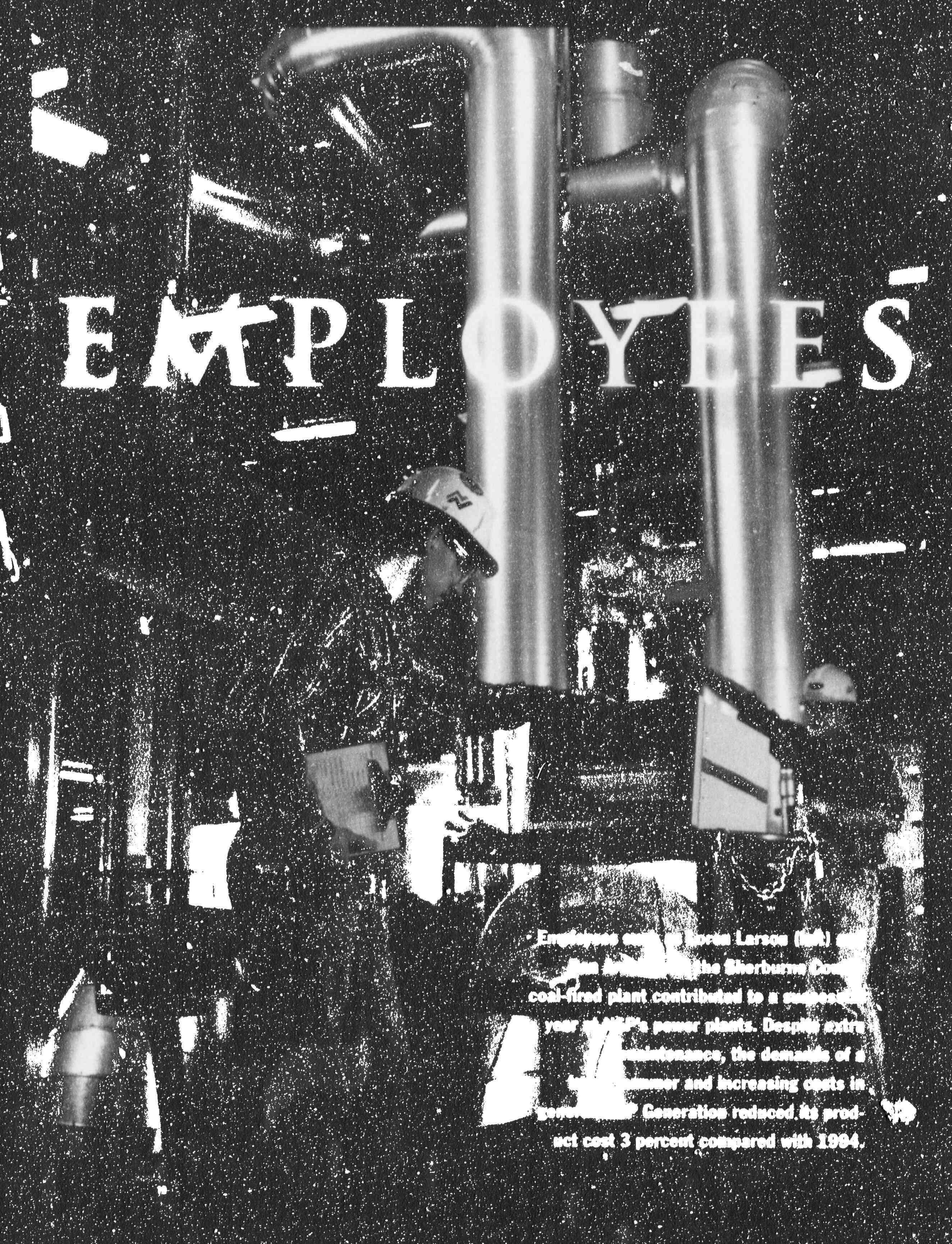
NSP also works closely with builders and developers, another group of important customers. In 1995, NSP marked the first anniversary of its customer service guarantee program, which guarantees builders and developers an installation date for electric and natural gas service, and ensures that NSP crews will restore sites to their original condition following an installation.

The program exceeded original expectations and is receiving positive customer feedback. In addition, the guarantees have reduced NSP's own design and construction costs by improving workload management.

Workforce-effectiveness improvements benefit customers and contribute to NSP's bottom line. In 1995, NSP initiated a significant work process redesign for NSP Electric's distribution area that resulted in productivity improvements of 12 percent compared with 1994. At NSP's warehousing operations in Maple Grove, Minnesota, workforce-effectiveness improvements have reduced warehousing costs by 52 percent since 1993, while increasing the amount of material handled per hour by 47 percent.

Those improvements demonstrate employees' commitment to cost control and customer service, but few events showcased NSP employee dedication and determination as dramatically as the 1995 heat storms. Two record-setting heat waves sent electric demand soaring to new highs of 7,439 megawatts on June 20 and 7,519 megawatts on July 13.

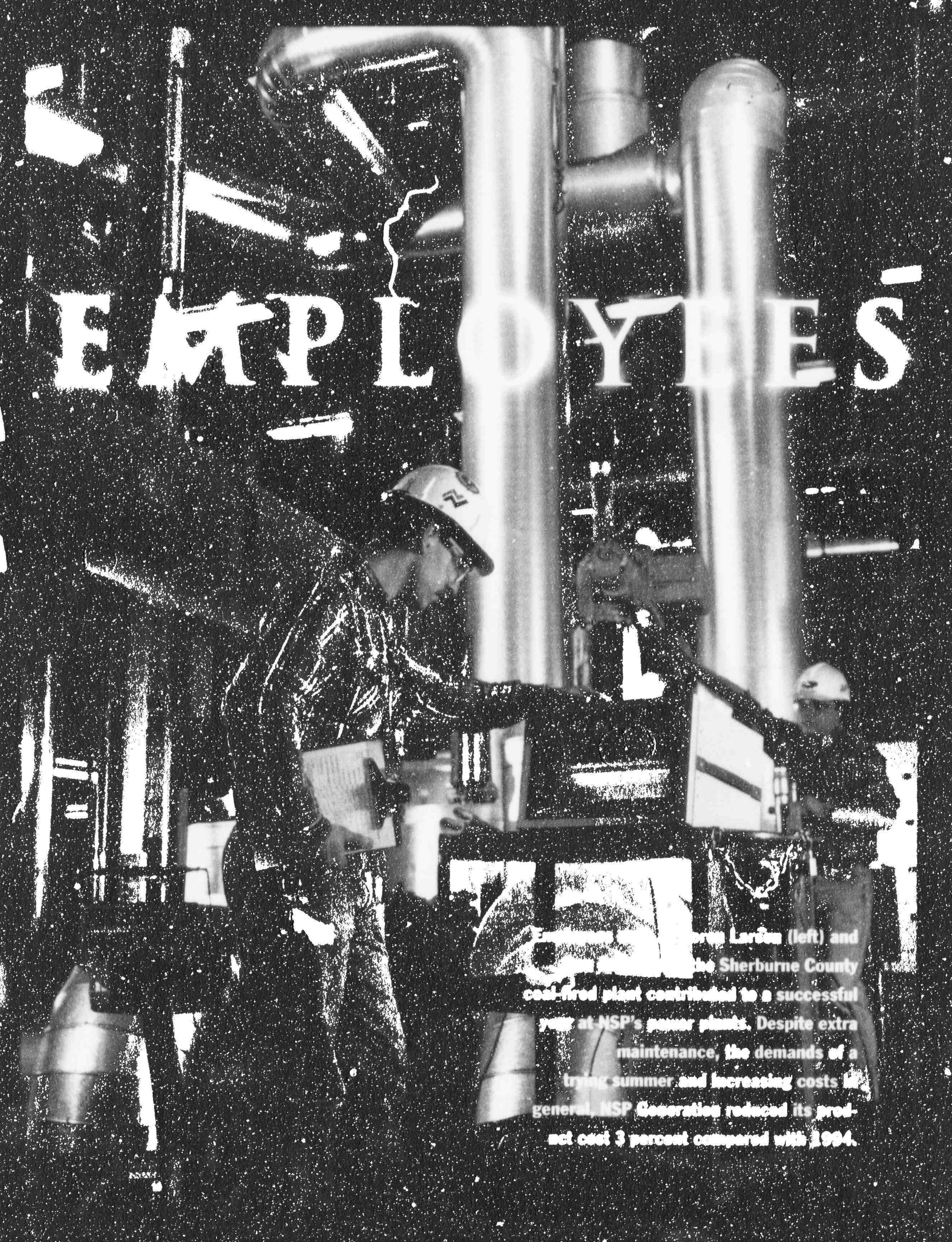
High demand for sustained periods puts NSP's generation and distribution systems to the test and places enormous burdens on our workforce. Once again, however, NSP employees were equal to the challenge. Our line crews, power plant workers, control center operators, engineers and customer representatives worked around the clock to ensure an adequate electric supply and restore power when outages occurred.



EMPLOYEES

Employees such as Loren Larson (left) and Jim [illegible] at the Sherburne Co[illegible] coal-fired plant contributed to a successful year at NSP's power plants. Despite extra [illegible] maintenance, the demands of a [illegible] summer and increasing costs in [illegible] Generation reduced its product cost 3 percent compared with 1994.

EMPLOYEES



Em[illegible] Larson (left) and [illegible] the Sherburne County coal-fired plant contributed to a successful year at NSP's power plants. Despite extra maintenance, the demands of a trying summer and increasing costs in general, NSP Generation reduced its product cost 3 percent compared with 1994.

The heat also tested the effectiveness of NSP's energy management programs, including the Saver's Switch®, Peak-Control and Energy-Control programs. Saver's Switch® reduces peak load by cycling participants' central air conditioners on and off for 15-minute intervals. Peak-Control and Energy-Control programs require participants to reduce their electric use when NSP is nearing its highest, or peak, level of electric demand in exchange for substantially reduced energy bills. Using the programs, NSP eliminated 550 megawatts from its peak load during those critical hot days.

Record-setting heat waves in 1995 tested **NSP** employees and systems. Both were equal to the challenge.

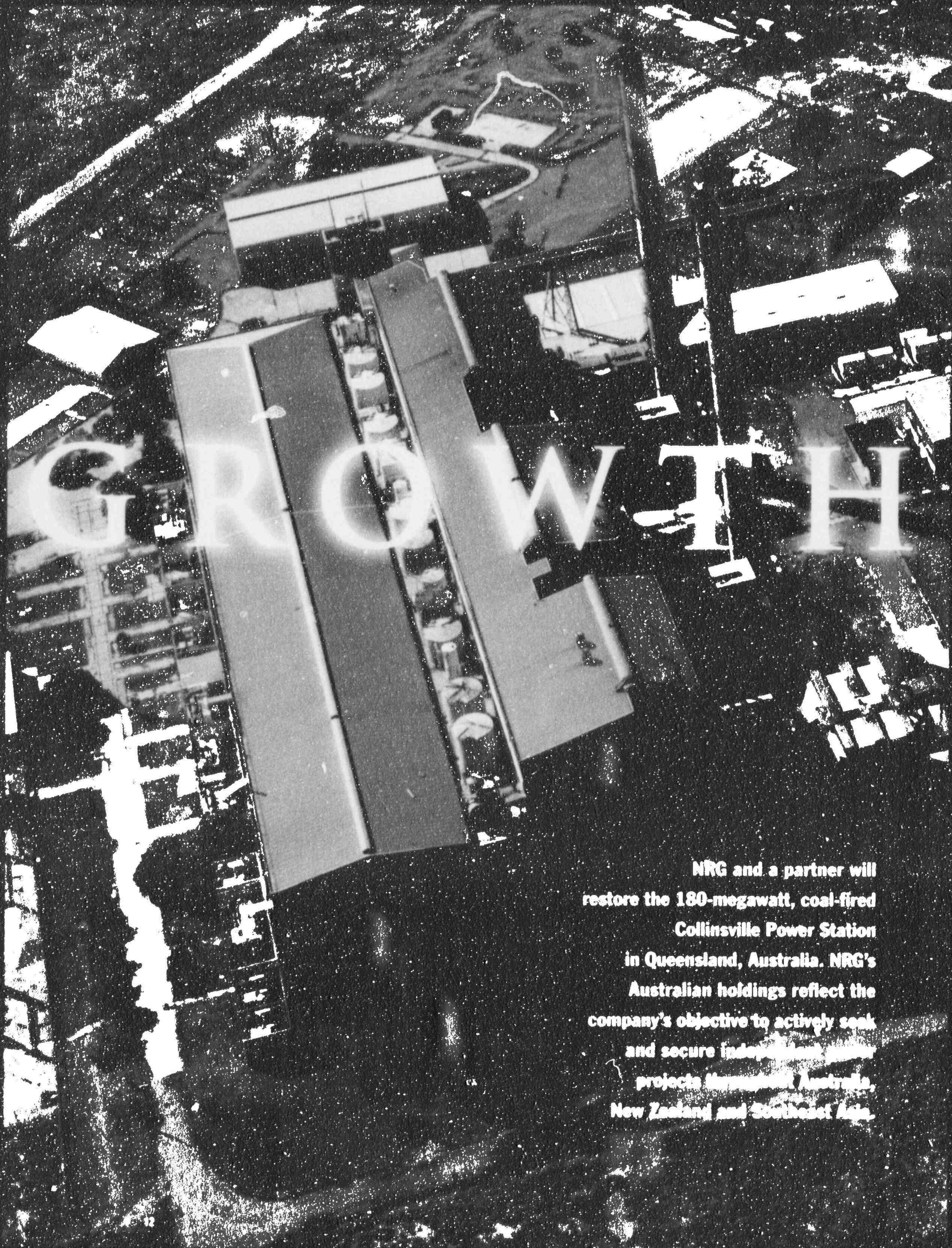
NSP's electric generating plants performed admirably during the heat as well. The company operated many of its peaking units, those plants used during times of high energy demand. The Angus Anson peaking plant, which went into service in September 1994 and uses two natural-gas-fired turbines, proved especially reliable and cost-effective.

Safe, efficient, reliable operations also characterize the company's nuclear generating units, which include the Prairie Island and Monticello plants. In 1995, the Monticello plant received a top rating from the Institute of Nuclear Power Operations (INPO), indicating the plant's overall operations were excellent. Monticello also achieved an availability record when it completed 375 days of continuous operation at year-end and was still going strong. Prairie Island, which holds a No. 1 rating from INPO as well, was identified as a top performer by the Nuclear Energy Institute. Both plants received high marks from the Nuclear Regulatory Commission in its most recent assessments.

NSP's coal-fired and hydroelectric plants finished 1995 with outstanding operating records. Our Sherburne County coal-fired plant once again achieved an availability rating higher than 90 percent, compared with the industry average of 82 percent. Our Allen S. King plant remains among the 50 lowest-cost coal-fired plants in the country.

The company's 19 Wisconsin hydroelectric plants generated 968,065 megawatt hours, a 16 percent increase over 1994. At the Chippewa Falls hydroelectric plant, crews completed an $8.8 million renovation, increasing the plant's turbine efficiency from 76 percent to 92 percent, gaining additional capacity and allowing it to operate another 40 years. The Chippewa Falls renovation is consistent with the company's strategy to keep its existing assets viable and maximize the use of a site for the long term.

Another important NSP focus is to secure avenues for profitable growth, which is the goal of our non-regulated operations. Once again, those businesses completed an excellent year.



NRG and a partner will restore the 180-megawatt, coal-fired Collinsville Power Station in Queensland, Australia. NRG's Australian holdings reflect the company's objective to actively seek and secure independent power projects throughout Australia, New Zealand and Southeast Asia.

GROWTH

NRG and a partner will restore the 180-megawatt, coal-fired Collinsville Power Station in Queensland, Australia. NRG's Australian holdings reflect the company's objective to actively seek and secure [illegible] projects [illegible] New Zea[illegible]

Our wholly owned subsidiary NRG Energy, Inc. (NRG) and a partner own a 400-megawatt share of the 960-megawatt Schkopau coal-fired generating plant, located near Leipzig, Germany. The first Schkopau unit began its startup process in November 1995 and was declared commercially operational in January 1996. Schkopau burns brown coal, which comes from the nearby MIBRAG industrial complex, also owned by NRG and partners. The second Schkopau unit is expected to begin commercial operation in June 1996.

In Queensland, Australia, NRG operates the 1,680-megawatt, coal-fired Gladstone Power Station. NRG made significant improvements to environmental protection systems at the plant, which ran smoothly in its second year of NRG operation. In December 1995, NRG signed an agreement to operate and partially own the Collinsville Power Station, a 180-megawatt, coal-fired plant also located in Queensland.

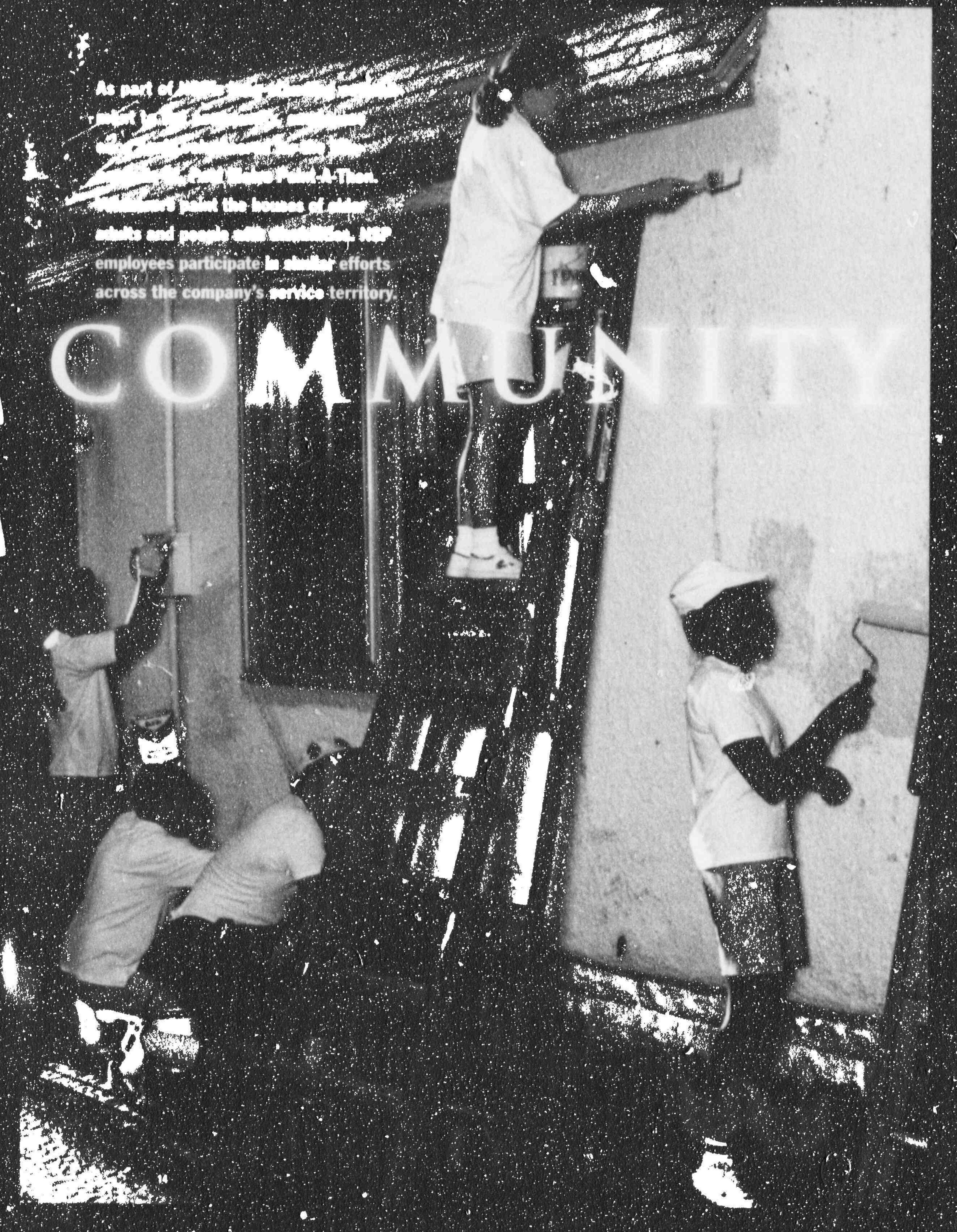
With the growing popularity of girls' hockey, **NSP Gas** has discovered a promising market for desiccant dehumidification systems for new and existing ice arenas. Fueled by natural gas, the system dehumidifies ice arenas more efficiently than conventional methods.

NRG's domestic operations include the Minneapolis Energy Center, which won several contracts in 1995, including cooling the new Federal Reserve Bank under construction in Minneapolis, and heating Fairview Riverside Hospital and Augsburg College. NRG also acquired a 50 percent interest in Thermal Ventures Incorporated, which operates the district heating systems in Pittsburgh and San Francisco.

The NEO Corporation (NEO), an NRG subsidiary, is successfully operating 11 small hydroelectric facilities across the United States and two generating plants that use renewable landfill gas as fuel. NEO has exclusive rights to develop at least 12 additional landfill gas projects.

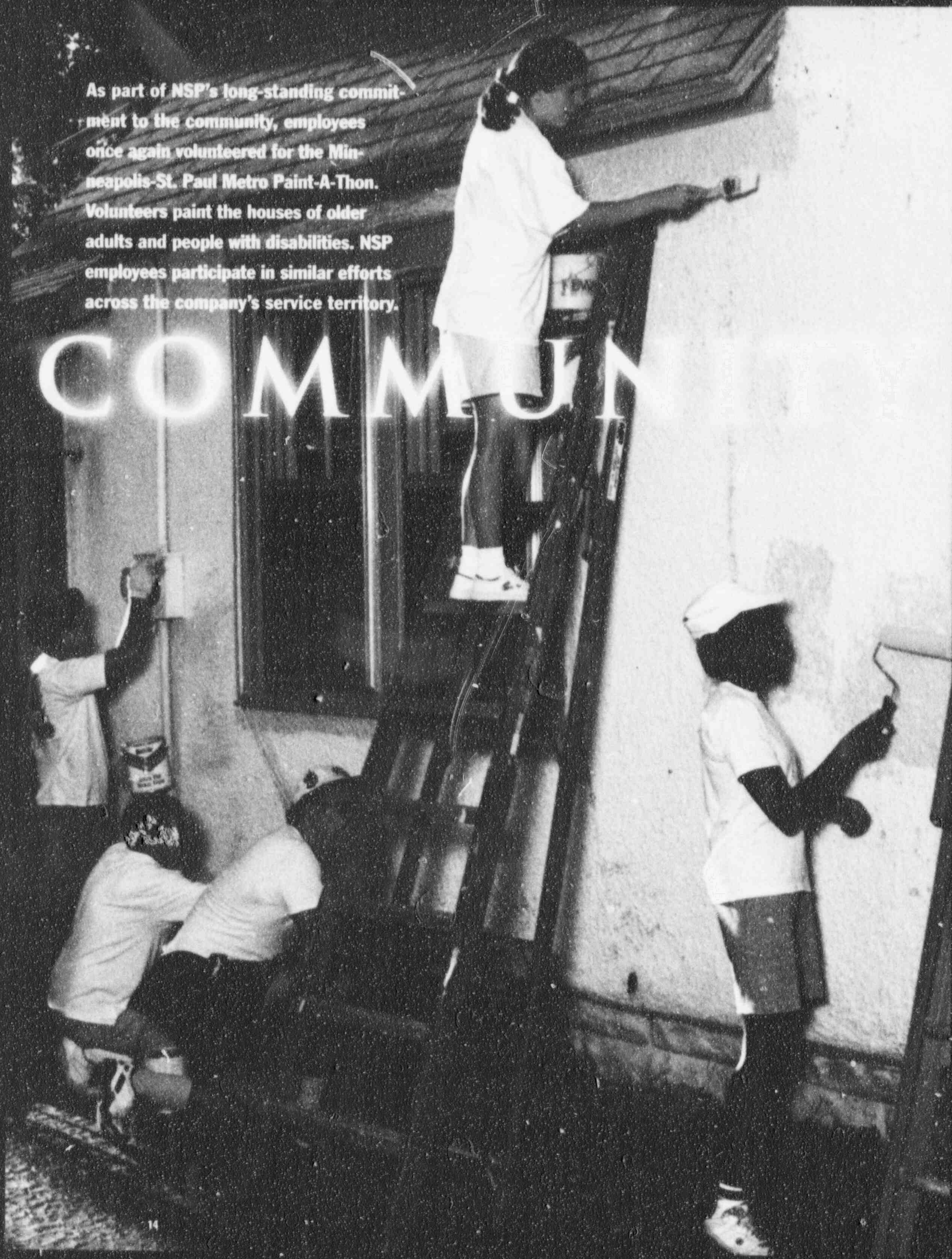
Cenergy, Inc., which became Cenerprise, Inc. on January 1, 1996, is another non-regulated NSP subsidiary showing great potential. Cenerprise markets energy management services, natural gas and electricity nationwide. In delivering energy management services, the company develops a five- to 10-year energy partnership with customers that typically includes analyzing energy use, developing and implementing efficiency improvements, helping to arrange financing for capital improvements and guaranteeing projected savings.

NSP Gas added more new customers in 1995 than ever before, signing up 16,708 by year-end. Many of them were in the Brainerd Lakes area, where in 1994 NSP Gas initiated its largest gas expansion ever. The utility also is aggressively pursuing a strategy to sign up customers on existing NSP gas lines.



As part of [illegible] project [illegible] [illegible] Paint-A-Thon. Volunteers paint the houses of older adults and people with disabilities. NIP employees participate in similar efforts across the company's service territory.

COMMUNITY



As part of NSP's long-standing commitment to the community, employees once again volunteered for the Minneapolis-St. Paul Metro Paint-A-Thon. Volunteers paint the houses of older adults and people with disabilities. NSP employees participate in similar efforts across the company's service territory.

COMMUN

Like NSP's electric business, NSP Gas is relying on new technology to improve productivity and customer service. NSP technicians who locate underground electric and natural gas lines at customers' request are using a new computerized field operation system that incorporates radio communications technology to transmit data to and from the field. The system has increased productivity 5 percent and reduced dispatch and administrative duties by 50 percent.

NSP employee Barb Thomas (left) became a good friend of Beverly (center) and Tammie Thornton after participating in the **Homeless To Home** project, which links homeless families to housing in the Minneapolis-St. Paul area. During 1995, NSP employees moved 12 families into a place they could call home.

At NSP's wholly owned subsidiary, Viking Gas Transmission Co. (Viking), plans are under way to expand Viking's existing service to the Minnesota communities of Perham and Randall and industrial customer American Crystal Sugar, and begin serving ProGold, LLC, a new industrial customer in North Dakota. The company will install 13.5 miles of new pipeline as part of the expansion, which is scheduled for 1996.

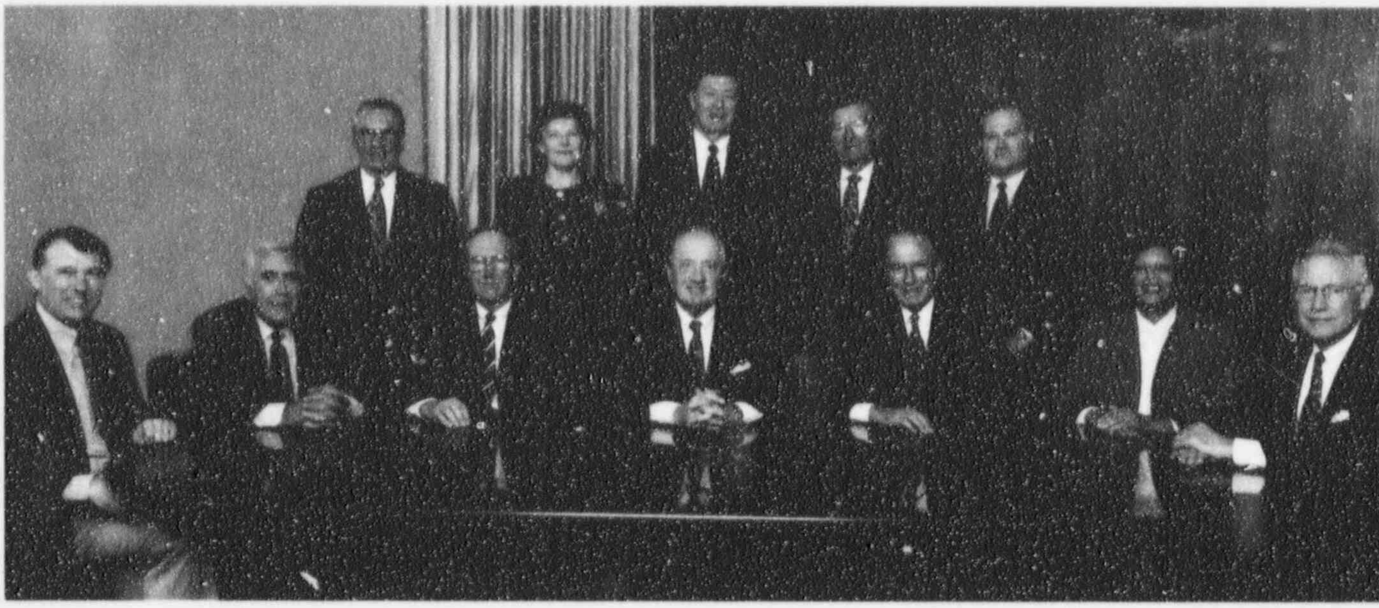
As NSP moves rapidly into a marketplace filled with greater uncertainties, our energy will remain focused on customers and working with them to identify and meet or exceed their needs. We will look in particular for opportunities that contribute to customers' competitiveness and our own profitabil

To improve customer service and increase productivity, we will invest in new technology when it makes sense. We also will rely on workforce-effectiveness measures to accomplish those goals.

Our regulated and non-regulated operations will remain poised to take advantage of opportunities for profitable growth. We recognize that our success depends on anticipating potential markets and moving quickly to capture them.

Finally, we will not abandon the fundamentals that made NSP a strong company in the past and will contribute to its competitiveness in the future as we merge with Wisconsin Energy to become Primergy. Those fundamentals include the recognition that our employees are instrumental to our success, and must be skilled and empowered; the belief that contributing to our communities remains important in a competitive market; and our ongoing commitment to environmental protection.

With those strategies in place and our willingness to pursue them aggressively, we have the energy for a bright tomorrow.



Board of Directors

Back row, left to right:
G.M. Pieschel, Dr. Margaret R. Preska, H. Lyman Bretting, Dale L. Haakenstad and Douglas W. Leatherdale

Front row, left to right:
Richard M. Kovacevich, John E. Pearson, W. John Driscoll, James J. Howard, Allen F. Jacobson, A. Patricia Sampson and David A. Christensen

Directors of the Minnesota Company

H. Lyman (Tad) Bretting (59) 3, 4
President and CEO
C. G. Bretting Manufacturing Company, Inc.
Manufacturer of napkin and paper towel folding machines
(elected March 1990)

David A. Christensen (61) 2, 4
President and CEO
Raven Industries, Inc.
Manufacturers of reinforced plastics, sewn products and electronic equipment
(elected December 1976)

W. John Driscoll (67) 1, 2
Retired Chairman of the Board and President
Rock Island Company
Private investment firm
(elected November 1974)

Dale L. Haakenstad (68) 1, 4
Retired President and CEO
Western States Life Insurance Company
(elected February 1978)

James J. Howard (60)*
Chairman of the Board, President and CEO
Northern States Power Company
(elected January 1987)

Allen F. Jacobson (69) 2, 4
Retired Chairman and CEO
Minnesota Mining and Manufacturing Company
(elected January 1983)

Richard M. Kovacevich (52) 3, 4
Chairman, President and CEO
Norwest Corporation
Holding company for banking institutions
(elected April 1990)

Douglas W. Leatherdale (59) 1, 2
Chairman of the Board, President and CEO
The St. Paul Companies, Inc.
Property and liability insurance organization
(elected April 1991)

John E. Pearson (69) 2, 3
Retired Chairman
The NWNL Companies, Inc. and Northwestern National Life Insurance Co.
(elected December 1983)

G.M. Pieschel (68) 1, 3
Chairman of the Board
Farmers and Merchants State Bank
(elected February 1978)

Dr. Margaret R. Preska (58) 2, 4
Distinguished Service Professor
Minnesota State Universities
(elected January 1980)

A. Patricia Sampson (47) 1, 3
Consultant
Dr. Sanders and Associates
A management and diversity consulting company
(elected January 1985)

Board Committees
1. Audit
2. Corporate Management
3. Finance
4. Power Supply

*James J. Howard is an *ex officio* member of all committees.

Principal Officers of the Minnesota Company

Douglas D. Antony (53)
President-NSP Generation

Arland D. Brusven (63)
Vice President-Finance

Jackie A. Currier (44)
Vice President and Treasurer

James J. Howard (60)
Chairman of the Board, President and CEO

Gary R. Johnson (49)
Vice President, General Counsel and Corporate Secretary

Cynthia L. Lesher (47)
Vice President-Human Resources

Edward J. McIntyre (45)
Vice President and CFO

Thomas A. Micheletti (49)
Vice President-Public and Government Affairs

Roger D. Sandeen (50)
Vice President, Controller and CIO

Loren L. Taylor (49)
President-NSP Electric

Edward L. Watzl (56)
Vice President-Nuclear Generation

Keith H. Wietecki (46)
President-NSP Gas

Directors of the Wisconsin Company

H. Lyman (Tad) Bretting (59)*
President and CEO
C. G. Bretting Manufacturing Company, Inc.
Manufacturer of napkin and paper towel folding machines
(elected March 1990)

Philip M. Gelatt (45)*
President
Northern Engraving Corporation
Manufacturer of decorative components for the automobile, appliance and electronic controls industries
(elected May 1990)

Wayne E. Harrison (68)
Dairy Farmer
(elected August 1990)

Ray A. Larson (66)*
President
Wissota Sand and Gravel Company
(elected November 1979)

John A. Noer (49)
Chairman, President and CEO
Northern States Power Company (Wisconsin)
(elected December 1992)

Larry G. Schnack (58)*
Chancellor
University of Wisconsin-Eau Claire
(elected May 1988)

Loren L. Taylor (49)
President-NSP Electric
NSP-Minnesota
(elected May 1992)

*Audit Committee members

Principal Officers of the Wisconsin Company

Michael N. Gregerson (48)
Vice President-Customer Services

John P. Moore, Jr. (49)
Secretary and General Counsel

John A. Noer (49)
Chairman, President and CEO

David E. Ripka (47)
Controller

Anthony G. Schuster (51)
Vice President-Power Delivery and Generation

Neal A. Siikarla (49)
Treasurer

Patrick D. Watkins (55)
Vice President-Corporate Services

Directors of NRG Energy, Inc.

Douglas D. Antony (53)
President-NSP Generation
(elected February 1995)

Jackie A. Currier (44)
Vice President and Treasurer
Northern States Power Company
(elected January 1993)

Gary R. Johnson (49)
Vice President, General Counsel and Corporate Secretary
Northern States Power Company
(elected February 1993)

Edward J. McIntyre (45)
Vice President and CFO
Northern States Power Company
(elected May 1992)

David H. Peterson (54)
Chairman, President and CEO
NRG Energy, Inc.
(elected July 1989)

Principal Officers of NRG Energy, Inc.

David H. Peterson (54)
Chairman of the Board, President and CEO

James J. Bender (39)
Assistant General Counsel and Corporate Secretary

Leonard A. Bluhm (50)
Vice President and CFO

Lee R. Carlson (56)
Treasurer

Carl A. Carreca (59)
Vice President
Executive Advisor to the Chairman

Julie A. Jorgensen (33)
Vice President and General Counsel

Valorie A. Knudsen (39)
Controller

Craig A. Mataczynski (35)
Vice President-U.S. Business Development

Robert McClenachan (44)
Vice President-International Business Development

Louise T. Routhe (39)
Vice President-Human Resources and Administration

Ronald J. Will (55)
Vice President-Operations and Engineering

Northern States Power Company, a Minnesota corporation (the Company), has two significant subsidiaries, Northern States Power Company, a Wisconsin corporation (the Wisconsin Company), and NRG Energy, Inc., a Delaware corporation (NRG). The Company also has several other subsidiaries, including Viking Gas Transmission Company (Viking) and Cenergy, Inc. (Cenergy), which changed its name to Cenerprise, Inc., effective Jan. 1, 1996. The Company and its subsidiaries collectively are referred to herein as NSP.

Financial Results and Objectives

1995 FINANCIAL RESULTS

NSP's 1995 earnings per share were $3.91, an increase of 45 cents, or 13.0 percent, over the $3.46 earned in 1994. The effects of sales growth in the core electric and gas utility businesses, favorable weather, and reduced operating and maintenance costs more than offset higher costs for depreciation, tax and interest expenses. This provided a regulated utility earnings increase of 44 cents, or 14.8 percent, from 1994. In 1995, non-regulated businesses contributed earnings of 50 cents, up 1 cent, or 2.0 percent, from 1994 earnings. Investor returns also were enhanced in 1995 by an increase in the common dividend rate, as discussed below.

NSP remained financially strong in 1995, as evidenced by continued high operating cash flows and interest coverage. NSP maintained its first mortgage bond ratings with all rating agencies during 1995. NSP bonds are rated double A by all rating agencies except Moody's Investors Services (Moody's). Moody's downgraded NSP's first mortgage bond ratings in May 1994 to A1 based on its interpretation of provisions of a Minnesota law enacted in 1994 regarding the used fuel storage project for the Prairie Island nuclear generating plant. (See discussion of this legislation in Notes 14 and 15 to the Financial Statements.) In 1995, Moody's placed the Company's ratings on credit review for possible upgrade based on anticipated cost savings from the proposed merger with Wisconsin Energy Corporation, which is discussed later.

TOTAL RETURN

Total return to investors is measured by dividends plus stock price appreciation. NSP's common dividend rate increased by more than 2 percent and its stock price increased by 11.6 percent in 1995. For the most recent 15-, 10- and five-year periods, the total return on NSP common stock averaged 18.1 percent, 12.7 percent and 13.8 percent per year, respectively. For the same periods, the total return for the Standard & Poor's (S&P) composite stock index for 500 industrial companies averaged 14.8 percent, 14.8 percent and 16.5 percent per year, respectively.

FINANCIAL OBJECTIVES

NSP's financial objectives are:

To provide investor returns in the top one-fourth of the utility industry as measured by a three-year average return on equity. NSP's average return on common equity for the three years ending in 1995 was 12.5 percent. Based on a three-year average, this return was below the top one-fourth of the industry, which was approximately 13.0 percent, but above the median three-year industry average of approximately 11.6 percent.

To increase dividends on a regular basis and maintain a long-term average payout ratio in the range of 65 to 75 percent. The objective payout ratio is based on long-term earnings expectations. In June 1995, NSP's annualized common dividend rate was increased by 6 cents per share, or 2.3 percent, from $2.64 to $2.70. The dividend payout ratio was 69 percent in 1995, within the objective range.

To maintain continued financial strength with a double A bond rating. The Company's first mortgage bonds continued to be rated AA- by S&P, AA- by Duff & Phelps, Inc. and AA by Fitch Investors Service, Inc. Since May 1994, Moody's has rated NSP's first mortgage bonds A1 based on its interpretations of a Minnesota law enacted in 1994 regarding the used fuel storage project for the Prairie Island nuclear generating plant. First mortgage bonds issued by the Wisconsin Company carry comparable ratings. NSP's pretax interest coverage ratio, based on income without Allowance for Funds Used During Construction (AFC), was 3.8 in 1995. A capital structure consisting of 48.4 percent common equity at year-end 1995, including both regulated and non-regulated operations, contributes to NSP's financial flexibility and strength.

To provide at least 20 percent of NSP earnings from NRG businesses by the year 2000. NRG expects to meet this goal through growing profitability of existing businesses and the addition of new businesses. Businesses owned or managed by NRG provided 12.4 percent of NSP's earnings in 1995 and 13.5 percent in 1994.

To maintain long-term average annual earnings growth of 5 percent from ongoing operations, as described below. Excluding the non-recurring items discussed later under Factors Affecting Results of Operations, NSP achieved earnings per share growth of 7.0 percent in 1995 over 1994 and an average annual growth of 10.5 percent since 1993.

	1995	1994	1993
Total earnings per share	**$3.91**	$3.46	$3.02
Less earnings from non-recurring items	**0.22**	0.01	
Earnings from ongoing operations	**$3.69**	$3.45	$3.02

Total earnings per share increased 13.0 percent in 1995 over 1994.

BUSINESS STRATEGIES

NSP's management is proactive in shaping the new business environment in which it will be operating. In April 1995, the Company and Wisconsin Energy Corporation (WEC) entered into a definitive agreement that provides for a strategic business combination in a "merger-of-equals" transaction to operate as Primergy Corporation (Primergy), as discussed further under Factors Affecting Results of Operations. Both companies' management teams view this transaction as creating a combined enterprise well-positioned for an increasingly competitive energy industry environment. The goal of the merger is to achieve continued competitive energy rates over the long term for the companies' respective customers and to enhance value for the shareholders of both companies. In addition to this merger strategy, management's business strategies include:

Focusing on the core energy business. The electric utility industry is becoming more complex as customers, as well as utilities and federal and state regulators, promote competition. To remain successful in

this more complex environment, NSP will maintain its focus on its core energy-related activities.

Providing reliable, low-cost, environmentally responsible energy. Whether energy is produced or purchased through NSP's regulated utility or its non-regulated businesses, three general concepts provide a focus for its energy businesses: reliable energy, low-cost energy and environmentally responsible energy.

Responding to customer needs. Customers will have an increasing number of options for meeting their energy needs, and there will be competition among energy companies for the privilege of serving those customers. NSP will work with its customers to develop innovative products and services that benefit both customers and NSP.

Increasing non-regulated investments and earnings. Non-regulated businesses will be an important part of NSP's future. Deregulation in the utility industry is expected to provide new investment opportunities in non-regulated businesses. Participation in these opportunities is expected to improve NSP's total profitability.

Results of Operations and Liquidity and Capital Resources

The following discussion and analysis by management focuses on those factors that had a material effect on NSP's financial condition and results of operations during 1995 and 1994. It should be read in conjunction with the accompanying Financial Statements and Notes thereto. Trends and contingencies of a material nature are discussed to the extent known and considered relevant. Material changes in balance sheet items are discussed below and in the accompanying Notes to Financial Statements. The discussion and analysis and the related financial statements do not reflect the impact of the Company's proposed merger with WEC except for pro forma information included in Note 18 to the Financial Statements.

Results of Operations

1995 Compared with 1994 and 1993

NSP's 1995 earnings per share were $3.91, up 45 cents from the $3.46 earned in 1994 and up 89 cents from the $3.02 earned in 1993. Regulated utility businesses generated earnings per share of $3.41 in 1995, $2.97 in 1994 and $2.93 in 1993. Non-regulated businesses generated earnings per share of 50 cents in 1995, 49 cents in 1994 and 9 cents in 1993. The results of the regulated utility businesses and the non-regulated businesses are discussed in more detail later. In addition to the revenue and expense changes, earnings per share have been affected by an increasing average number of common and equivalent shares outstanding. Common and equivalent shares increased in 1995 and 1994 due mainly to stock issuances for the Company's dividend reinvestment and stock ownership plans.

Utility Operating Results

Electric Revenues Sales to retail customers, which account for more than 90 percent of NSP's electric revenue, increased 4.2 percent in 1995 and 3.9 percent in 1994. Retail revenues were favorably affected by sales growth, weather and increased cost recovery for conservation expenditures. During 1995, NSP added 18,297 retail electric customers, a 1.3 percent increase. Total sales of electricity increased 2.9 percent in 1995 and decreased 0.2 percent in 1994. Warmer-than-normal summer weather in 1995 contributed to sales growth compared with 1994, which had a cooler-than-normal summer.

On a weather-adjusted basis, sales to retail customers increased an estimated 2.4 percent in 1995 and 3.4 percent in 1994. Retail sales growth for 1996 is estimated to be 0.8 percent over 1995, or 1.9 percent on a weather-adjusted basis.

Sales to other utilities increased 1.0 percent in 1995 after decreasing 21.6 percent in 1994. The 1994 decrease from 1993 largely was due to unusually high demand in 1993 from utilities in flood-stricken Midwestern states.

The table below summarizes the principal reasons for the electric revenue changes during the past two years:

(Millions of dollars)	**1995 vs. 1994**	1994 vs. 1993
Retail sales growth (excluding weather impacts)	**$46**	$56
Estimated impact of weather on retail sales volume	**42**	8
Sales to other utilities	**1**	(20)
Wholesale sales	**(13)**	7
Conservation cost recovery	**19**	2
Fuel adjustment clause recovery	**(7)**	23
Other rate changes	**(2)**	15
Energy management discounts and other	**(10)**	1
Total revenue increase	**$76**	$92

NSP's electric rates are adjusted for changes in fuel and purchased energy costs from amounts currently included in approved base rates through fuel adjustment clauses in all jurisdictions, except as noted below for Wisconsin. While the lag in implementing these billing adjustments is approximately 60 days, an estimate of the adjustments is recorded in unbilled revenue in the month in which costs are incurred. In Wisconsin, the biennial retail rate review process considers changes in electric fuel and purchased energy costs in lieu of a fuel adjustment clause.

In 1995, a new rate adjustment clause was approved. It accelerated recovery of deferred electric conservation and energy management program costs in the Company's Minnesota jurisdiction. This adjustment clause helps reduce the need for filing a general rate increase request for recovery of increases in conservation expenditures. The Company is required to request a new cost recovery level annually. In January 1996, a number of changes to the Company's regulatory deferral and amortization practices for Minnesota conservation program expenditures were approved. These changes allow the Company to expense rather than amortize new conservation expenditures beginning in 1996 and to increase its recovery of electric margins lost due to conservation activity. In addition, the Company received approval for 1996 and 1997 conservation expenditures at levels lower than 1995. On April 1, 1996, the Company expects to file for annual changes to the Minnesota conservation rate adjustment clause with an effective period of July 1, 1996, through June 30, 1997. Revenues in 1996 are expected to increase by an estimated $17 million, compared with 1995, due to the effects of the rate recovery changes for conservation programs in 1995 and 1996. These revenue increases will be largely offset by a corresponding increase in conservation expenses.

Electric Production Expenses Fuel expense for electric generation increased $4.5 million, or 1.4 percent, in 1995 compared with an increase of $5.6 million, or 1.8 percent, in 1994. The 1995 increase was primarily attributable to an increase in output from NSP's generating plants, resulting from increased sales and fewer scheduled plant maintenance outages. Although output from NSP's generating plants declined slightly in 1994 because of more scheduled fossil plant maintenance outages, fuel expenses were higher in 1994 because of the higher cost of nuclear fuel per megawatt-hour due to increased payments to the U.S. Department of Energy (DOE) for decommissioning and decontamination of the DOE's uranium enrichment facilities and nuclear fuel disposal costs. In addition, the costs of fossil fuel were higher in 1994 because of fewer coal purchases at the lowest contractual prices due to lower fossil plant output.

Purchased power costs decreased $5.2 million, or 2.1 percent, in 1995 after increasing $41.1 million, or 19.7 percent, in 1994. The decrease in 1995 was primarily due to lower average market prices and less energy purchased. The level of purchases declined due to fewer scheduled plant maintenance outages in 1995. The increase in 1994 primarily was due to additional demand expenses of $21 million for the full-year impact of capacity charges from the power purchase agreements with the Manitoba Hydro-Electric Board (MH), which went into effect in May 1993, as discussed in Note 15 to the Financial Statements. In addition to demand expenses, purchased power costs increased from 1993 due to higher average market prices and increased purchases because of more plant maintenance outages in 1994.

Gas Revenues The majority of NSP's retail gas sales are categorized as firm (primarily space heating customers) and interruptible (commercial/industrial customers with an alternate energy supply). Firm sales in 1995 increased 6.8 percent compared with 1994 sales, while firm sales in 1994 decreased 5.4 percent compared with 1993 sales. The 1995 increase primarily is due to increased sales of natural gas resulting from 16,680 additional new firm gas customers, a 4.1 percent increase, and slightly more favorable weather in 1995. The 1994 decrease was due largely to warm weather in the last quarter of 1994.

On a weather-adjusted basis, firm sales are estimated to have increased 4.6 percent in 1995 and decreased 0.7 percent in 1994. Firm gas sales in 1996 are estimated to increase by 2.6 percent relative to 1995, a 3.6 percent increase on a weather-adjusted basis.

Interruptible sales of gas increased 15.7 percent in 1995 and 4.4 percent in 1994. The 1995 increase is the result of favorable gas market prices that caused large interruptible customers with alternate fuel sources to use more natural gas. Other gas deliveries increased 46.1 percent in 1995 and 65.7 percent in 1994 primarily due to additional gas sales to off-system customers. Viking wholesale transmission deliveries increased 1.1 percent in 1995. These wholesale deliveries increased 74.3 percent in 1994 due to a full year of Viking activity.

The table below summarizes the principal reasons for the gas revenue changes during the past two years.

(Millions of dollars)	**1995 vs 1994**	1994 vs 1993
Sales growth (excluding weather impacts)	**$26**	$0
Estimated impact of weather on firm sales volume	**7**	(8)
Sales to off-system customers	**2**	14
Purchased gas adjustment clause recovery	**(26)**	(24)
Rate changes and other	**(3)**	4
Viking Gas (acquired in June 1993)		5
Total revenue increase (decrease)	**$6**	$(9)

NSP's retail gas rates are adjusted for changes in purchased gas costs from amounts currently included in approved base rates through purchased gas adjustment clauses in all jurisdictions. Effective November 1995, a new rate adjustment clause was approved that accelerated recovery of deferred gas conservation and energy management program costs in the Company's Minnesota jurisdiction, similar to the retail electric rate clause discussed previously. The Company estimates it will receive an additional $2.7 million in revenues from this new rate mechanism in 1996 compared with 1995. This increased recovery will result in a corresponding increase in conservation expenses.

Cost of Gas Purchased and Transported The cost of gas purchased and transported decreased $7.1 million, or 2.7 percent, in 1995 primarily due to a 12.6 percent decline in the per unit cost of purchased gas, partially offset by higher sendout volumes due to increased sales and off-system deliveries. The lower cost of purchased gas reflects continuing favorable market pricing, while the higher gas sendout reflects sales growth in 1995 and higher gas sales to off-system customers. The cost of gas associated with off-system sales was $14.3 million in 1995 and $12.7 million in 1994. The cost of gas purchased and transported decreased $18.6 million, or 6.6 percent, in 1994. The decrease reflects lower gas prices and cost recovery adjustments, partially offset by higher sendout volumes primarily for gas sales to off-system customers. The average cost per unit of NSP-owned gas sold in 1994 was 8.4 percent lower than it was in 1993, mainly due to lower market prices for gas.

Other Operation, Maintenance and Administrative and General These expenses, in total, decreased by $9.1 million, or 1.4 percent, in 1995 compared with an increase of $26.0 million, or 4.0 percent, in 1994. The 1995 decrease is largely due to fewer employees, fewer scheduled plant maintenance outages, lower property insurance premiums and a one-time charge in 1994 for postemployment benefits. Partially offsetting these decreases were higher employee benefit costs, and higher electric line maintenance costs, mostly for tree trimming and heat-related repairs. The 1994 increase resulted primarily from higher postretirement health care costs, including amounts deferred from 1993, and higher postemployment costs as discussed in Note 2 to the Financial Statements. (See Note 12 to the Financial Statements for a summary of administrative and general expenses.)

Conservation and Energy Management Expenses in 1995 were higher than in 1994 primarily due to higher amortization levels of deferred conservation program costs, consistent with cost recovery under new

electric and gas rate adjustment clauses in the Company's Minnesota jurisdiction effective May 1, 1995, and Nov. 1, 1995, respectively. The deferred costs being amortized are higher due to increased customer participation in NSP's conservation and energy management programs.

Depreciation and Amortization The increases in 1995 and 1994 reflect higher levels of depreciable plant.

Property and General Taxes Property and general taxes increased in 1995 and 1994 primarily due to property additions and higher property tax rates.

Utility Income Taxes The variations in income taxes primarily are attributable to fluctuations in taxable income. (See Note 9 to the Financial Statements for a detailed reconciliation of the statutory tax rate to NSP's effective tax rate.)

NON-OPERATING ITEMS RELATED TO UTILITY BUSINESSES

Allowance for Funds Used During Construction (AFC) The differences in AFC for the reported periods are attributable to varying levels of construction work in progress and changing AFC rates associated with various levels of short-term borrowings to fund construction. In addition, returns allowed on deferred costs for conservation and energy management programs increased AFC-equity by $2.6 million and $2.0 million in 1995 and 1994, respectively, and increased AFC-debt by the amounts of $1.5 million and $0.9 million in 1995 and 1994, respectively.

Other Income (Expense) Note 12 to the Financial Statements lists the components of Other Income (Deductions)-Net reported on the Consolidated Statements of Income. Other than the operating revenues and expenses of non-regulated businesses, as discussed in the next section, non-operating income (net of expense items and associated income taxes) related to utility businesses increased $5.6 million in 1995 and decreased $2.4 million in 1994. The 1995 increase primarily is due to higher expense levels in 1994 for environmental and regulatory contingencies, and public and governmental affairs costs related to the Prairie Island fuel storage issue. These were partly offset by lower interest income associated with the Company's settlement of federal income tax disputes in 1995. The 1994 decrease primarily is due to higher expenses for environmental and regulatory contingencies, and higher public and governmental affairs expenses associated with the Prairie Island fuel storage issue, partially offset by interest income associated with the Company's settlement of federal income tax disputes.

Interest Charges (Before AFC) Interest costs recognized for NSP's utility businesses, including amounts capitalized to reflect the financing costs of construction activities, were $123.4 million in 1995, $107.1 million in 1994 and $110.4 million in 1993. The 1995 increase is largely due to long-term debt issues in 1995 and 1994 (net of retirements) and higher short-term interest rates, which affect commercial paper borrowings and variable rate long-term debt. The 1994 decrease reflects the impact of refinancing several higher-rate long-term debt issues in 1993 and 1994. These interest savings were partially offset by interest on higher short-term debt balances and Viking debt (issued late in 1993). The average short-term debt balance was $208.7 million in 1995, $204.5 million in 1994 and $77.0 million in 1993.

Preferred Dividends Dividends on the Company's preferred stock decreased in 1994 primarily due to redemption of the $7.84 Series Cumulative Preferred Stock in October 1993.

NON-REGULATED BUSINESS RESULTS

NSP's non-regulated operations include many diversified businesses, such as independent power production, gas marketing, industrial heating and cooling, and energy-related refuse-derived fuel (RDF) production. NSP also has investments in affordable housing projects and several income-producing properties. The following discusses NSP's diversified business results in the aggregate.

Operating Revenues and Expenses The net results of non-regulated businesses that are consolidated are reported in Other Income (Deductions)-Net on the Consolidated Statements of Income. (Note 12 to the Financial Statements lists the individual components of this line item.) Non-regulated operating revenues increased $71.3 million, or 29 percent, in 1995, and $151.3 million, or 167 percent, in 1994. The 1995 increase was largely due to increased gas marketing sales by Cenergy. The 1994 increase was mainly due to the impact of Cenergy gas marketing and NRG industrial heating and cooling businesses acquired in 1993. Non-regulated operating expenses increased in 1995 primarily due to higher gas costs associated with Cenergy gas sales and higher project development expenses by NRG on pending projects. Non-regulated operating expenses increased in 1994 consistent with revenue increases resulting from 1993 acquisitions. In addition, such expenses increased in 1994 due to fewer project development costs being capitalized on pending projects in 1994 compared with 1993, and project write-downs. Non-regulated operating expenses include charges of $5.0 million in 1995 and $5.0 million in 1994 for previously capitalized development and investment costs to reflect a decrease in the expected future cash flows of certain energy projects.

Equity in Operating Earnings NSP has a less-than-majority equity interest in many non-regulated projects, as discussed in Note 3 to the Financial Statements. Consequently, a large portion of NSP's non-regulated earnings is reported as Equity in Earnings of Unconsolidated Affiliates on the Consolidated Statements of Income. The 1995 decrease in equity in project operating earnings is due to lower earnings from an NRG cogeneration project contract that was terminated in 1995 and other domestic projects, somewhat offset by higher earnings from NRG international energy projects (one of which did not provide earnings prior to the second quarter of 1994). The 1994 increase in equity in project operating earnings primarily is due to new international energy projects in which NRG entered during 1994 (as discussed in Note 3 to the Financial Statements), and more profitable operations of other energy projects in which NRG had been an investor for several years.

Equity in Gains From Contract Terminations In June 1995, after receiving final regulatory approvals, a power sales contract between a California energy project, in which NRG is a 45 percent investor, and an unaffiliated utility company was terminated. A pretax gain of approximately $30 million was recognized by NRG for its share of the termination settlement. In 1994, a Michigan cogeneration project, in which NRG was a 50 percent investor, received a payment from an unaffiliated utility company as compensation for the termination of an energy purchase agreement. A pretax gain of $9.7 million was recognized by NRG for its share of the contract termination settlement, net of project investment costs.

Other Income (Expense) Other than the operating revenues and expenses of non-regulated businesses, as discussed above, non-operating income (net of expense items) related to non-regulated businesses increased $4.7 million in 1995 and increased $0.8 million in 1994. The 1995 increase primarily is due to a gain on the sale of Cenergy oil and gas properties, higher income from cash investments, and an adjustment to the 1994 contract termination gain recorded by NRG.

Interest Expense Interest charges on the Consolidated Statements of Income include interest and amortization expenses related to non-regulated businesses. The expenses were $9.9 million in 1995, $8.0 million in 1994 and $3.1 million in 1993. The increase in 1995 mainly is due to the issuance of long-term debt on new affordable housing projects by Eloigne Company, a wholly owned subsidiary of the Company. The increase in 1994 relates primarily to non-utility long-term debt issued to finance the 1993 acquisitions of NRG's industrial heating and cooling business (Minneapolis Energy Center), a gas marketing business now operated by Cenergy, and 1994 investments in affordable housing projects by Eloigne Company. In addition, during 1994 and late 1993, United Power & Land and First Midwest Auto Park, wholly owned subsidiaries of the Company, issued long-term debt secured by non-regulated properties and lowered NSP's equity investment in these subsidiaries.

Income Taxes The Consolidated Statements of Income include income tax expense related to non-regulated businesses of $6.1 million in 1995, $2.6 million in 1994 and $3.5 million in 1993. The increase in 1995 mainly is due to a gain from an NRG energy contract termination, as discussed previously, somewhat offset by higher income tax credits from Eloigne Company's affordable housing projects. The decrease in 1994 mainly is due to higher income tax credits from affordable housing projects and energy tax credits related to an NRG project, somewhat offset by higher taxes due to higher operating earnings, as discussed above. The effective tax rate in 1995 and 1994 is substantially less than the U.S. federal tax rate mainly due to the tax treatment of income from unconsolidated international affiliates, and energy and affordable housing tax credits, as shown in Note 9 to the Financial Statements.

FACTORS AFFECTING RESULTS OF OPERATIONS

NSP's results of operations during 1995, 1994 and 1993 were primarily dependent upon the operations of the Company's and Wisconsin Company's utility businesses consisting of the generation, transmission, distribution and sale of electricity and the distribution, transportation and sale of natural gas. NSP's utility revenues depend on customer usage, which varies with weather conditions, general business conditions, the state of the economy and the cost of energy services. Various regulatory agencies approve the prices for electric and gas service within their respective jurisdictions. In addition, NSP's non-regulated businesses are contributing significantly to NSP's earnings. The historical and future trends of NSP's operating results have been and are expected to be affected by the following factors:

Proposed Merger On April 28, 1995, the Company and WEC entered into an Agreement and Plan of Merger that provides for a business combination of NSP and WEC in a "merger-of-equals" transaction. As a result of the mergers contemplated by the merger agreement, Primergy will become the holding company for the regulated operations of both the Company and the utility subsidiary of WEC. The business combination is intended to be tax-free for income tax purposes, and accounted for as a "pooling of interests." On Sept. 13, 1995, more than 95 percent of the respective shareholders of the Company and WEC voting approved the merger plan at their respective shareholder meetings. Under the proposed business combination, shareholders of the Company would receive 1.626 shares of Primergy common stock for each share of the Company's common stock owned at the time of the merger.

After the merger is completed, a transition to a new organization would begin. Anticipated cost savings of the new organization (compared with the continued independent operation of NSP and WEC) are estimated to be $2 billion over a 10-year period, net of transaction costs (about $30 million) and costs to achieve the merger savings (about $122 million). It is anticipated that the proposed merger will allow the companies to implement a modest reduction in electric retail rates and a four-year rate freeze for electric retail customers. In addition, the companies agreed to provide a four-year freeze in wholesale rates. After the merger, the regulated businesses of NSP and WEC would continue to operate as utility subsidiaries of Primergy, which would be registered under the Public Utility Holding Company Act of 1935 (PUHCA), as amended, and some of the Company's subsidiaries would be transferred to direct Primergy ownership. Except for certain gas distribution properties transferred to the Company, the Wisconsin Company will become part of the regulated business of WEC. Although NSP and WEC are working to avoid divestitures, the PUHCA may require the merged entity to divest certain of its gas utility and/or non-regulated operations. Also, regulatory authorities may require the restructuring of transmission system operations or administration. NSP currently cannot determine if such divestitures or restructuring would be required. In addition, Wisconsin state law limits the total assets of non-utility affiliates of Primergy. This could affect the growth of non-regulated operations.

The agreement to merge is subject to a number of conditions, including approval by applicable regulatory authorities. During 1995, NSP and WEC received a ruling from the Internal Revenue Service indicating that the proposed successive merger transactions would not prevent treatment of the business combination as a tax-free reorganization under applicable tax law if each transaction independently qualified. During 1995, NSP and WEC submitted filings to the Federal Energy Regulatory Commission (FERC), applicable state regulatory commissions and other governmental authorities seeking approval of the proposed merger to form Primergy. The FERC has put the merger application on an accelerated schedule, ordering the administrative law judge's initial decision by Aug. 30, 1996, and briefs on exception by Sept. 30, 1996, which makes possible a FERC ruling on the merger application by the end of 1996. Although the goal of NSP and WEC is to receive approvals from all regulatory authorities by the end of 1996, some regulatory authorities have not established a timetable for their decisions. Therefore, the timing of the approvals necessary to complete the merger is not known at this time. The state filings included a request for deferred accounting treatment and rate recovery of costs incurred associated with the proposed merger. At Dec. 31, 1995, $13.9 million of costs associated with the proposed merger had been deferred as a component of Intangible and Other Assets. In February 1996, the appropriate committees of the Minnesota Legislature passed legislation that would affect

merger approval for electric utilities. This bill, if passed into law, would provide for certain binding commitments regarding minimum levels of staffing and investment for electric service.

In addition to the regulatory and other governmental approvals of the proposed merger, certain NSP financial and other agreements may be construed to require that, in the case of a change in ownership (such as the proposed merger), the other party to the agreement must consent to the change or waive the requirement. Agreements with such provisions at Dec. 31, 1995, include $101.7 million of long-term debt, operating lease agreements with annual payments of $1.3 million in 1996 and a $10 million credit line agreement, under which there were no borrowings at Dec. 31, 1995. Although neither consents nor waivers from the other parties have yet been obtained, NSP will seek to obtain them prior to the completion of the merger. (See further discussion of the proposed business combination in Note 18 to the Financial Statements.)

Regulation NSP's utility rates are approved by the FERC, the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission, the Public Service Commission of Wisconsin (PSCW), the Michigan Public Service Commission and the South Dakota Public Utilities Commission. Rates are designed to recover plant investment and operating costs and an allowed return on investment, using an annual period upon which rate case filings are based. NSP requests changes in rates for utility services as needed through filings with the governing commissions. The rates charged to retail customers in Wisconsin are reviewed and adjusted biennially. Because comprehensive rate changes are not requested annually in Minnesota, NSP's primary jurisdiction, changes in operating costs can affect NSP's earnings, shareholders' equity and other financial results. Except for Wisconsin electric operations, NSP's rate schedules provide for cost-of-energy and resource adjustments to billings and revenues for changes in the cost of fuel for electric generation, purchased energy, purchased gas, and conservation and energy management program costs. For Wisconsin electric operations, the biennial retail rate review process considers changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In addition to changes in operating costs, other factors affecting rate filings are sales growth, conservation and demand-side management efforts and the cost of capital.

Competition The Energy Policy Act of 1992 (the Act) was a catalyst for comprehensive and significant changes in the operation of electric utilities, including increased competition. The Act's reform of the PUHCA promotes creation of wholesale non-utility power generators and authorizes the FERC to require utilities to provide wholesale transmission services to third parties. The legislation allows utilities and non-regulated companies to build, own and operate power plants nationally and internationally without being subject to restrictions that previously applied to utilities under the PUHCA. Management believes this legislation will promote the continued trend of increased competition in the electric energy markets. NSP management plans to continue its efforts to be a competitively priced supplier of electricity and an active participant in the competitive market for electricity. The proposed merger with WEC is a key strategic initiative designed to facilitate NSP's effective competition in the future energy marketplace.

In March 1995, the FERC issued a Notice of Proposed Rulemaking on Open Access Non-discriminatory Transmission Services and a Supplemental Notice of Proposed Rulemaking on Stranded Investment (together called the Mega-NOPR). The Mega-NOPR is intended to create a vigorous wholesale electric market by requiring transmission providers to offer open access to their transmission systems. The FERC is proposing to require utilities to unbundle power sales from transmission. This "unbundled service" requirement would apply only to new requirements contracts and new coordination trade contracts. The Mega-NOPR would apply to all utilities under the FERC's jurisdiction and would require each utility to file individual tariffs. The FERC also seeks to require non-jurisdictional transmission-providing entities (such as municipals and cooperatives) to offer open access by including a reciprocity clause in their individual tariffs so that those who take service from a FERC jurisdictional utility must also offer open access. Concurrently with the Mega-NOPR, the FERC issued a proposal for a Real-Time Information Network intended to facilitate open access by requiring all public utilities to create an electronic bulletin board of information regarding their transmission system services, availability and rates. Also in the Mega-NOPR, the FERC proposed to consider cases involving stranded costs resulting from open access (a) when a state regulatory commission does not have authority under state law to address such costs at the time retail wheeling (which is the transmission to retail customers of power generated by a third party in competition with supplies from the host utility) takes place, and (b) after a state commission has addressed such costs. In response to the FERC's proposals, NSP filed comments with the FERC that supported the Mega-NOPR's open access initiative and asserted NSP's intent that open access transmission tariffs filed in 1994 comply with the spirit of the Mega-NOPR. NSP expects the impact of any rulemaking such as the Mega-NOPR to be consistent with its efforts to be a competitively priced supplier of electricity and an active participant in the competitive market for electricity.

With the development of electric industry competition, the Company has experienced an increase in requests for the use of its transmission system. A large portion of these requests is due to the increase in FERC-approved power marketers. In 1995, the Company filed 23 transmission service agreements for FERC approval, including 10 with power marketers. While the annual transmission revenue in 1995 from this activity was immaterial, it is expected that 1996 revenues will increase due to the growth of power marketing activity in this region.

In response to the developing electric industry competition, Cenergy applied for and was granted permission by the FERC to market electricity (except electricity generated by NSP) in the United States, effective Dec. 1, 1994. Cenergy was one of the first affiliates of an electric utility to obtain this approval from the FERC.

Some states are considering proposals to increase competition in the supply of electricity. In response to a proposal in 1994 by its regulator in Wisconsin, NSP outlined the transitional steps necessary to create an open and fair competitive electric market. NSP's position is that all customers should be able to choose their electric supplier by 2001, and that generation also should be deregulated by 2001. NSP proposes that utilities retain operational control of their transmission and distribution systems, and that utilities should be permitted to recover the cost of investments made under traditional regulation. Regulators

in Minnesota and Wisconsin are currently considering what actions they should take regarding electric industry competition. In Wisconsin, regulators developed a plan for a phased approach. They voted to adopt a restructuring plan, which includes a 32-step phase-in of retail wheeling by the year 2001. A key component of the plan is to provide the protections necessary to ensure that consumers are not harmed in an increasingly competitive environment. One component of the plan is to have an independent system operator control transmission access. In Minnesota, regulators have developed draft principles to provide a framework for electric industry restructuring. They have not established definitive timelines for industry restructuring or changes. One of the principles supports an open transmission system and establishing a robust wholesale competitive market. NSP believes the transition to a more competitive electric industry is inevitable and beneficial for all consumers. NSP supports an orderly and efficient transition to an open, fair and competitive energy market for all customers and suppliers. The timing of regulatory actions and their impact on NSP cannot be predicted and may be significant.

During 1992 and 1993, the FERC issued a series of orders (together called Order 636) addressing interstate natural gas pipeline service restructuring. This restructuring "unbundled" each of the services (sales, transportation, storage and ancillary services) traditionally provided by gas pipeline companies. Interstate pipelines have been allowed to recover from their customers 100 percent of prudently incurred transition costs attributable to Order 636 restructuring. Under service agreements that went into effect Nov. 1, 1993, NSP estimates that it will be responsible for less than $11 million of transition costs over a five-year period beginning on that date. To date, NSP's regulatory commissions have approved recovery of these restructuring charges in retail gas rates through the purchased gas adjustment. NSP does not believe Order 636 has materially affected its cost of gas supply. NSP's acquisitions of Viking and Cenergy in 1993 have enhanced its ability to participate in the more competitive gas transportation business. In implementing Order 636, Viking incurred no transition costs.

Customer Cogeneration Koch Refining Co. (Koch), the Company's largest customer, which provides approximately $30 million in annual revenues to NSP, proposes to build a cogeneration plant to burn petroleum coke, a refinery byproduct, to produce between 180 and 250 megawatts of electricity. This would be enough supply for Koch's own use plus an additional 80 to 150 megawatts to be sold on the wholesale market. Koch is requesting a legislative exemption from Minnesota property tax for its plant. While NSP supports the reduction of taxes on generating facilities, it believes any reduction should be applied to all generating facilities so that there are no unfair tax advantages available to some generators. This project has several implications for NSP: 1) Koch could become a competitor as it seeks markets for its excess capacity; 2) Koch's capacity would also represent a potential power source for NSP; and 3) Koch's plan represents a potential loss of a large retail customer. The project's anticipated three-year lead time will allow NSP to respond appropriately.

Wholesale Customers NSP had wholesale revenues from sales of electricity of approximately $44 million in 1995 and approximately $57 million in 1994. The trend of increased competition, as previously discussed, has resulted in significant changes in the negotiation of contracts with wholesale customers. In the past several years, these customers have begun to evaluate a variety of energy sources to provide their power supply. While the full impact of these changes is unknown at this time, the following changes have been identified.

In 1992, nine of the Company's municipal wholesale electric customers notified the Company of their intent to terminate their power supply agreements with the Company, effective July 1995 or July 1996. The loss of seven of these customers in July 1995 resulted in a revenue decrease of approximately $12 million from 1994 levels. The other two customers, who are expected to terminate their power agreements in July 1996, provided revenues of $3.6 million in 1995. These nine customers are expected to become wheeling customers providing estimated annual revenues of nearly $3 million. NSP's remaining 19 municipal wholesale electric customers are under contracts with terms expiring in the years 1999 through 2008.

During 1993, the Company signed an electric power agreement to provide Michigan's Upper Peninsula Power Company (UPPCO) with up to 150 megawatts of baseload service, peaking service options and load regulation service options for 20 years from January 1998 through December 2017. Load regulation service is designed to change the level of power delivery during each hour to match UPPCO's load requirements. UPPCO has nominated 50 megawatts of baseload and five megawatts of winter season peaking power purchases from NSP beginning Jan. 1, 1998. The annual revenue for 1998 is projected to be approximately $11 million to $14 million. The interchange agreement between UPPCO and NSP for this sale was accepted by the FERC. The Michigan Public Utilities Commission also must approve the transaction.

Rate Changes As discussed previously under Utility Operating Results, filings for rate changes in 1995 had an immaterial impact on financial results. No significant general rate filings in any of NSP's utility jurisdictions are expected for 1996. However, the Company has proposed rate changes in connection with requested approvals of its proposed business combination with WEC, as discussed previously.

Used Nuclear Fuel Storage and Disposal In 1994, NSP received legislative authorization from the State of Minnesota for dry cask fuel storage facilities at the Company's Prairie Island nuclear generating facility. As a condition of this authorization, the Minnesota Legislature established several resource commitments for the Company, including wind and biomass generation sources, as well as other requirements. In addition, the Company and other utilities filed a lawsuit against the DOE in 1994 to compel the DOE to fulfill its statutory and contractual obligations to store and dispose of used nuclear fuel as required by the Nuclear Waste Policy Act of 1982. Also, the Company is leading a consortium to establish a private facility for interim storage of used nuclear fuel, the outcome of which is uncertain at this time. (See Notes 14 and 15 to the Financial Statements for more information.)

Environmental Matters NSP incurs several types of environmental costs, including nuclear plant decommissioning, storage and ultimate disposal of used nuclear fuel, disposal of hazardous materials and wastes, remediation of contaminated sites and monitoring of discharges into the environment. Because of the continuing trend toward greater environmental awareness and increasingly stringent regulation, NSP has been experiencing a trend toward increasing environmental costs. This trend has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance. In addition to nuclear decommissioning and

used nuclear fuel disposal expenses (as discussed in Note 14 to the Financial Statements), costs charged to NSP's operating expenses for environmental monitoring and disposal of hazardous materials and wastes in 1995 were approximately $26 million and are expected to increase to an average annual amount of approximately $30 million for the five-year period 1996-2000. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. In each of the years 1995, 1994 and 1993, the Company spent about $15 million for capital expenditures on environmental improvements at its utility facilities. In 1996, the Company expects to incur approximately $20 million in capital expenditures for compliance with environmental regulations and approximately $180 million for the five-year period 1996-2000. These capital expenditure amounts include the costs of constructing used nuclear fuel storage casks. (See Notes 14 and 15 to the Financial Statements for further discussion of these and other environmental contingencies that could affect NSP.)

Weather NSP's earnings can be significantly affected by unusual weather. In 1995, unusual weather, mainly a hot summer, increased earnings over a normal year by an estimated 21 cents per share. Mild weather, mainly cool summers, reduced earnings from a normal year by an estimated 13 cents per share in 1994 and 18 cents per share in 1993. The effect of weather is considered part of NSP's ongoing business operations.

Acquisitions In 1994, NRG acquired ownership interests in three significant international energy projects (listed in Note 3 to the Financial Statements). NSP also made three other strategically important business acquisitions in 1993, including an interstate natural gas pipeline (Viking), an energy services marketing business (Cenergy) and a steam heating and chilled water cooling system business (Minneapolis Energy Center, now an NRG subsidiary). NSP continues to evaluate opportunities to enhance its competitive position and shareholder returns through strategic business acquisitions.

Impact of Non-regulated Investments NSP's net income includes after-tax earnings of $33.6 million, or 50 cents per share, from all of its non-regulated businesses in 1995 and $32.9 million, or 49 cents per share, in 1994. As discussed previously, NRG acquired equity interests in three significant energy projects in 1994. NSP expects to continue investing significant amounts in non-regulated projects, including domestic and international power production projects through NRG, as described under Future Financing Requirements. Depending on the success and timing of involvement in these projects, NSP's goal is for NRG earnings to increase in the future to contribute at least 20 percent of NSP's earnings by the year 2000. The non-regulated projects in which NRG has invested carry a higher level of risk than NSP's traditional utility businesses. Current and future investments in non-regulated projects are subject to uncertainties prior to final legal closing, and continuing operations are subject to foreign government actions, foreign economic and currency risks, partnership actions, competition, operating risks, dependence on certain suppliers and customers, domestic and foreign environmental and energy regulations, or all of these items. Most of NRG's current project investments consist of minority interests, and a substantial portion of future investments may take the form of minority interests, which limits NRG's ability to control the development or operation of the projects. In addition, significant expenses may be incurred for potential projects pursued by NRG that may never materialize. The operating results of NSP's non-regulated businesses in 1995 and 1994 may not necessarily be indicative of future operating results.

Accounting Changes The Financial Accounting Standards Board (FASB) has issued two new accounting standards that become effective in 1996. Statement of Financial Accounting Standards (SFAS) No. 121, Accounting for the Impairment of Long-Lived Assets, establishes standards for measuring and recognizing asset impairments. SFAS No. 123, Accounting for Stock-Based Compensation, provides an optional accounting method for compensation from stock option and other stock award programs that NSP does not intend to use. NSP does not expect the adoption of these new accounting standards to have a material impact on its results of operations or financial condition. However, the principles of SFAS No. 121 will be followed to measure the effects of any stranded investments that could arise from the Act, the FERC's Mega-NOPR proposal or other competitive business developments.

The FASB also has proposed new accounting standards expected to go into effect in 1997. The standards would require the full accrual of nuclear plant decommissioning and certain other site exit obligations. Material adjustments to NSP's balance sheet could occur under the FASB's proposal. However, the effects of regulation are expected to minimize or eliminate any impact on operating expenses and earnings from this future accounting change. (For further discussion of the expected impact of this change, see Note 14 to the Financial Statements.)

Use of Derivatives Through its non-regulated subsidiaries, NSP uses derivative financial instruments to hedge the risks of fluctuations in foreign currencies and natural gas prices. Also, to hedge the interest rate risk associated with fixed rate debt in a declining interest rate environment, NSP uses interest rate swap agreements to convert fixed rate debt to variable rate debt. (See Notes 1 and 11 to the Financial Statements for further discussion of NSP's financial instruments and derivatives.)

Non-recurring Items NSP's earnings for 1995 include two significant unusual or infrequently occurring items. As discussed in the Non-regulated Business Results section, NRG recognized a pretax gain of approximately $30 million (26 cents per share) from a power sales contract termination settlement. Partially offsetting this gain was an asset impairment write-down of $5 million before taxes (4 cents per share) for a non-regulated domestic energy project.

NSP's 1994 earnings also included several significant unusual or infrequently occurring items. Although their net effect was an earnings increase of only 1 cent per share, individually significant non-recurring items included a gain on termination of a non-regulated cogeneration contract, interest income from the settlement of a federal income tax dispute, a charge for pre-1994 postemployment costs associated with adopting SFAS No. 112, and asset impairment write-downs for certain non-regulated energy projects.

Inflation Historically, certain operating costs, mainly labor and property taxes, have been affected by inflation. Also, inflation has tended to increase the replacement cost of operating facilities, which has increased depreciation expense when replacement facilities are constructed. However, several significant expense items, including fuel costs, income taxes and interest expense have been less sensitive to inflation. Overall, inflation at the levels currently being experienced is not expected to materially affect NSP's prices to customers or returns to shareholders.

Liquidity and Capital Resources

1995 Financing Requirements NSP's need for capital funds is primarily related to the construction of plant and equipment to meet the needs of electric and gas utility customers and to fund equity commitments or other investments in non-regulated businesses. Total NSP utility capital expenditures (including AFC) were $386 million in 1995. Of that amount, $318 million related to replacements and improvements of NSP's electric system and nuclear fuel, and $37 million involved construction of natural gas distribution facilities. NSP companies invested $71 million in non-regulated projects and property in 1995. NRG primarily invested in existing projects. In 1995, Cenergy became a majority investor (80 percent) in Energy Masters Corporation, a firm specializing in energy efficiency improvement services for commercial, industrial and institutional customers. The investment is accounted for on a consolidated basis. Eloigne Company invested in affordable housing projects, including wholly owned and limited partnership ventures.

1995 Financing Activity During 1995, NSP's primary sources of capital included internally generated funds, long-term debt, short-term debt and common stock issuances, as discussed below. The allocation of financing requirements between these capital options is based on the relative cost of each option, regulatory restrictions and the constraints of NSP's long-range capital structure objectives. During 1995, NSP continued to meet its long-range regulated capital structure objective of 45-50 percent common equity and 42-50 percent debt.

Funds generated internally from operating cash flows in 1995 remained sufficient to meet working capital needs, debt service, dividend payout requirements and non-regulated investment commitments, as well as fund a significant portion of construction expenditures. The pretax interest coverage ratio, excluding AFC, was 3.8 in 1995 and 3.9 in 1994. These ratios met NSP's objective range of 3.5-5.0 for interest coverage. Internally generated funds could have provided financing for 85 percent of NSP's total capital expenditures for 1995 and 72 percent of the $1.9 billion in capital expenditures incurred for the five-year period 1991-1995.

NSP had approximately $216 million in short-term borrowings outstanding as of Dec. 31, 1995. Throughout 1995, short-term borrowings were used to finance a portion of utility capital expenditures and provide for other NSP cash needs.

In 1995, the Company issued $250 million of first mortgage bonds to refinance higher-cost debt issues and reduce short-term debt levels. Eloigne Company also issued approximately $12.5 million of long-term debt to finance affordable housing project investments.

During 1995, the Company issued new shares of common stock under various stock plans, including 536,360 new shares under the Employee Stock Ownership Plan (ESOP), 527,671 new shares under the Dividend Reinvestment and Stock Purchase Plan (DRSPP), and 63,780 new shares under the Executive Long-Term Incentive Award Stock Plan. In addition, the Company issued common stock in connection with a non-regulated business acquisition. At Dec. 31 1995, the total number of common shares outstanding was 68,175,934.

NSP's equity investments in non-regulated projects during 1995 were financed through internally generated funds. Project financing requirements, in excess of equity contributions from investors, were satisfied with project debt. Project debt associated with many of NSP's non-regulated investments is not reflected in NSP's balance sheet because the equity method of accounting is used for such investments. (See Note 3 to the Financial Statements.)

In January 1996, NRG issued $125 million of 7.625 percent unsecured Senior Notes maturing in 2006 to support equity requirements for projects currently under way and in development. The Senior Notes were assigned ratings of BBB- by S&P's Rating Group and Baa3 by Moody's.

Future Financing Requirements Utility financing requirements for 1996-2000 may be affected in varying degrees by numerous factors, including load growth, changes in capital expenditure levels, rate changes allowed by regulatory agencies, new legislation, market entry of competing electric power generators, changes in environmental regulations and other regulatory requirements. NSP currently estimates that its utility capital expenditures will be $410 million in 1996 and $1.9 billion for the five-year period 1996-2000. Of the 1996 amount, approximately $345 million is scheduled for utility electric facilities and approximately $45 million for natural gas facilities, including Viking. In addition to utility capital expenditures, expected financing requirements for the 1996-2000 period include approximately $480 million to retire long-term debt and meet first mortgage bond sinking fund requirements.

Through its subsidiaries, NSP expects to invest significant amounts in non-regulated projects in the future. Financing requirements for non-regulated project investments may vary depending on the success, timing and level of involvement in projects currently under consideration. NSP's potential capital requirements for non-regulated projects and property are estimated to be approximately $140 million in 1996 and approximately $550 million for the five-year period 1996-2000. These amounts include commitments for NRG investments, as discussed in Note 15 to the Financial Statements, and Eloigne Company investments of up to $13 million annually in 1996-2000 for affordable housing projects. Eloigne Company expects to finance approximately 65 percent of these investments in affordable housing projects with equity and approximately 35 percent with long-term debt. In addition to investments in non-regulated projects, NSP continues to evaluate opportunities to enhance shareholder returns and achieve long-term financial objectives through acquisitions of existing businesses. Long-term financing may be required for such investments.

The Company also will have future financing requirements for the portion of nuclear plant decommissioning costs not funded externally. Based on the most recent decommissioning study, these amounts are anticipated to be approximately $363 million, and are expected to be paid during the years 2010 to 2022.

Future Sources of Financing NSP expects to obtain external capital for future financing requirements by periodically issuing long-term debt, short-term debt, common stock and preferred stock as needed to maintain desired capitalization ratios. Over the long-term, NSP's equity investments in non-regulated projects are expected to be financed through internally generated funds or the Company's issuance of common stock. Financing requirements for the non-regulated projects, in

excess of equity contributions from investors, are expected to be fulfilled through project or subsidiary debt. Decommissioning expenses not funded by an external trust are expected to be financed through a combination of internally generated funds, long-term debt and common stock. The extent of external financing to be required for nuclear decommissioning costs, as discussed above, is unknown at this time.

NSP's ability to finance its utility construction program at a reasonable cost and to provide for other capital needs depends on its ability to meet investors' return expectations. Financing flexibility is enhanced by providing working capital needs and a high percentage of total capital requirements from internal sources, and having the ability to issue long-term securities and obtain short-term credit. NSP expects to maintain adequate access to securities markets in 1996. Access to securities markets at a reasonable cost is determined in large part by credit quality. The Company's first mortgage bonds are rated AA- by Standard & Poor's Corporation, A1 by Moody's Investors Service, Inc. (Moody's), AA- by Duff & Phelps, Inc., and AA by Fitch Investors Service, Inc. Ratings for the Wisconsin Company's first mortgage bonds are generally comparable. These ratings reflect the views of such organizations, and an explanation of the significance of these ratings may be obtained from each agency. In May 1994, Moody's downgraded the Company's first mortgage bond ratings to A1 based on its interpretation of provisions of a Minnesota law enacted in 1994 for used nuclear fuel storage at the Prairie Island generating plant. (The other three rating agencies reaffirmed their ratings of the Company's bonds after considering the potential impact of the legislation on NSP.) As discussed in Notes 14 and 15 to the Financial Statements, the legislation requires the Company to increase its use of renewable energy sources such as wind and biomass power. Moody's has indicated that it believes these sources of power are considerably more costly than the power currently generated and that NSP's electric production costs will increase materially over current levels. NSP acknowledges that electric production costs may increase as a result of the Prairie Island legislation. In 1995, Moody's placed the Company's ratings on credit review for possible upgrade based on anticipated cost savings from the proposed merger with WEC, which was discussed previously.

The Company's and the Wisconsin Company's first mortgage indentures limit the amount of first mortgage bonds that may be issued. The MPUC and the PSCW have jurisdiction over securities issuance. At Dec. 31, 1995, with an assumed interest rate of 7.0 percent, the Company could have issued about $2.5 billion of additional first mortgage bonds under its indenture, and the Wisconsin Company could have issued about $356 million of additional first mortgage bonds under its indenture.

The Company filed a shelf registration for first mortgage bonds with the Securities and Exchange Commission (SEC) in October 1995. Depending on capital market conditions, the Company expects to issue the $300 million of registered, but unissued, bonds over the next several years to raise additional capital or redeem outstanding securities. In addition, depending on market conditions, the Wisconsin Company may issue up to $65 million in first mortgage bonds to redeem outstanding securities or raise additional capital.

The Company's Board of Directors has approved short-term borrowing levels up to 10 percent of capitalization. The Company has received regulatory approval for up to $445 million in short-term borrowing levels and plans to keep its credit lines at or above its average level of commercial paper borrowings. Commercial banks presently provide credit lines of approximately $265 million to the Company and an additional $17 million to subsidiaries of the Company. These credit lines make short-term financing available in the form of bank loans.

The Company's Articles of Incorporation authorize the maximum amount of preferred stock that may be issued. Under these provisions, the Company could have issued all $460 million of its remaining authorized, but unissued, preferred stock at Dec. 31, 1995, and remained in compliance with all interest and dividend coverage requirements.

The level of common stock authorized under the Company's Articles of Incorporation is 160 million shares. In January 1996, the Company filed a registration statement with the SEC to provide for the sale of up to 1.6 million additional shares of new common stock under the Company's Dividend Reinvestment and Stock Purchase Plan (DRSPP) and Executive Long-Term Incentive Award Stock Plan. The Company may issue new shares or purchase shares on the open market for its stock-based plans. (See Note 5 to the Financial Statements for discussion of stock awards outstanding.) The Company plans to issue new shares for its DRSPP, ESOP and Executive Long-Term Incentive Award Stock plans in 1996. While no general public stock offerings are currently anticipated in 1996, such offerings may be necessary to fund significant equity investments in non-regulated projects should they occur.

Internally generated funds from utility operations are expected to equal approximately 90 percent of anticipated utility capital expenditures for 1996 and approximately 100 percent of the $1.9 billion in anticipated utility capital expenditures for the five-year period 1996-2000. Internally generated funds from all operations are expected to equal approximately 75 percent and 90 percent, respectively, of the anticipated total capital expenditures for 1996 and the five-year period 1996-2000. Because NSP intends to reinvest foreign cash flows in non-U.S. operations, the equity income from international investments currently does not provide operating cash available for U.S. cash requirements such as payment of dividends, domestic capital expenditures and domestic debt service. Through NRG, NSP intends to pursue a diverse portfolio of foreign energy projects with varying levels of cash flows, income and foreign taxation to allow maximum flexibility of foreign cash flows.

The merger agreement, as previously discussed, provides for restrictions on certain transactions by both the Company and WEC, including the issuance of debt and equity securities. While the Company currently does not plan to enter into transactions that would not comply with these restrictions, circumstances may arise to make such transactions necessary. Under such circumstances, the Company and WEC would need to mutually agree to amend the merger agreement.

(Thousands of dollars, except per share data)	1995	Year Ended Dec. 31 1994	1993
Utility Operating Revenues			
Electric	$2 142 770	$2 066 644	$1 974 916
Gas	425 814	419 903	429 076
Total	2 568 584	2 486 547	2 403 992
Utility Operating Expenses			
Electric production expenses – fuel and purchased power	570 245	570 880	524 126
Cost of gas purchased and transported	256 758	263 905	282 036
Other operation	321 121	316 479	310 585
Maintenance	158 203	170 145	161 413
Administrative and general	186 147	187 996	176 617
Conservation and energy management	53 468	31 231	29 358
Depreciation and amortization	290 184	273 801	264 517
Property and general taxes	239 433	234 564	223 108
Income taxes	147 146	129 228	128 346
Total	2 222 705	2 178 229	2 100 106
Utility Operating Income	345 879	308 318	303 886
Other Income (Expense)			
Equity in earnings of unconsolidated affiliates:			
Earnings from operations	29 217	32 024	3 030
Gain from contract termination	29 850	9 685	
Allowance for funds used during construction – equity	6 794	4 548	7 328
Other income (deductions) – net	(7 975)	(3 686)	7 982
Income taxes on non-regulated operations and non-operating items	(5 080)	(199)	(2 394)
Total	52 806	42 372	15 946
Income Before Interest Charges	398 685	350 690	319 832
Interest Charges			
Interest on utility long-term debt	103 298	89 553	101 677
Other utility interest and amortization	20 151	17 555	8 739
Non-regulated interest and amortization	9 879	7 975	3 146
Allowance for funds used during construction – debt	(10 438)	(7 868)	(5 470)
Total	122 890	107 215	108 092
Net Income	275 795	243 475	211 740
Preferred Stock Dividends	12 449	12 364	14 580
Earnings Available for Common Stock	$263 346	$231 111	$197 160
Average Number of Common and Equivalent Shares Outstanding (000's)	67 416	66 845	65 211
Earnings Per Average Common Share	$3.91	$3.46	$3.02
Common Dividends Declared per Share	$2.685	$2.625	$2.565

See Notes to Financial Statements on pages 34 to 49

(Thousands of dollars)	1995	Year Ended Dec. 31 1994	1993
Cash Flows from Operating Activities:			
Net Income	$275 795	$243 475	$211 740
Adjustments to reconcile net income to cash from operating activities:			
Depreciation and amortization	322 296	304 583	286 855
Nuclear fuel amortization	49 778	45 553	43 120
Deferred income taxes	(11 076)	(6 101)	12 256
Deferred investment tax credits recognized	(9 117)	(9 501)	(9 223)
Allowance for funds used during construction – equity	(6 794)	(4 548)	(7 328)
Undistributed equity in earnings of unconsolidated affiliate operations	(24 305)	(23 588)	(1 142)
Undistributed equity in gain from non-regulated contract termination settlements	(17 565)		
Cash provided by (used for) changes in certain working capital items	(791)	(8 627)	33 259
Conservation program expenditures – net of amortization	(21 668)	(29 963)	(21 185)
Cash provided by (used for) changes in other assets and liabilities	17 234	(1 042)	12 340
Net Cash Provided by Operating Activities	573 787	510 241	560 692
Cash Flows from Investing Activities:			
Capital expenditures:			
Utility businesses	(386 072)	(387 026)	(356 836)
Non-regulated businesses	(14 984)	(22 260)	(4 859)
Increase (decrease) in construction payables	(12 538)	11 668	2 598
Allowance for funds used during construction – equity	6 794	4 548	7 328
Sale (purchase) of short-term investments – net	743	(866)	62
Investment in external decommissioning fund	(33 196)	(42 677)	(32 578)
Business acquisitions			(159 385)
Equity investments in non-regulated projects and other	(55 859)	(132 511)	(25 957)
Net Cash Used for Investing Activities	(495 112)	(569 124)	(569 627)
Cash Flows from Financing Activities:			
Change in short-term debt – net issuances (repayments)	(22 245)	132 239	(40 361)
Proceeds from issuance of long-term debt	277 174	367 184	613 120
Loan to ESOP	(15 000)		
Repayment of long-term debt, including reacquisition premiums	(195 683)	(272 097)	(489 106)
Proceeds from issuance of common stock	56 185	1 368	183 654
Redemption of preferred stock, including premium			(36 092)
Dividends paid	(191 367)	(186 568)	(180 220)
Net Cash Provided by (Used for) Financing Activities	(90 936)	42 126	50 995
Net Increase (Decrease) in Cash and Cash Equivalents	(12 261)	(16 757)	42 060
Cash and Cash Equivalents at Beginning of Period	41 055	57 812	15 752
Cash and Cash Equivalents at End of Period	$28 794	$41 055	$57 812
Cash Provided by (Used for) Changes in Certain Working Capital Items:			
Customer accounts receivable and unbilled utility revenues	$(66 311)	$14 708	$(43 219)
Materials and supplies inventories	14 290	(13 462)	13 911
Payables and accrued liabilities (excluding construction payables)	53 141	32 550	54 247
Customer rate refunds	(1 825)	(10 410)	12 235
Other	(86)	(32 013)	(3 915)
Net	$ (791)	$(8 627)	$33 259
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for:			
Interest (net of amount capitalized)	$113 705	$106 867	$107 037
Income taxes (net of refunds received)	$131 452	$170 474	$120 491

See Notes to Financial Statements on pages 34 to 49

(Thousands of dollars)	Dec. 31 1995	1994
Assets		
Utility Plant		
Electric – including construction work in progress: 1995, $137,662; 1994, $117,235	$6 553 383	$6 372 317
Gas	710 035	677 233
Other	299 585	262 506
Total	7 563 003	7 312 056
Accumulated provision for depreciation	(3 343 760)	(3 116 811)
Nuclear fuel – including amounts in process: 1995, $34,235; 1994, $12 505	843 919	797 097
Accumulated provision for amortization	(752 821)	(718 690)
Net utility plant	4 310 341	4 273 652
Current Assets		
Cash and cash equivalents	28 794	41 055
Short-term investments	149	892
Customer accounts receivable – net of accumulated provision for uncollectible accounts: 1995, $4,338; 1994, $3,912	281 584	229 272
Unbilled utility revenues	112 058	98 651
Other receivables	78 993	80 444
Materials and supplies – at average cost		
Fuel	43 941	56 960
Other	100 607	101 878
Prepayments and other	57 745	56 075
Total current assets	704 463	665 227
Other Assets		
Regulatory assets	374 212	357 576
Non-regulated property – net of accumulated depreciation: 1995, $83,724; 1994, $73,296	177 598	172 961
Equity investments in non-regulated projects and other investments	289 495	197 490
External decommissioning fund investments	203 625	145 467
Long-term receivables	83 065	68 735
Intangible and other assets	85 786	68 624
Total other assets	1 213 781	1 010 853
Total	$6 228 585	$5 949 732
Liabilities and Equity		
Capitalization (See pages 32-33)		
Common stockholders' equity	$2 027 391	$1 896 967
Preferred stockholders' equity	240 469	240 469
Long-term debt	1 542 286	1 463 354
Total capitalization	3 810 146	3 600 790
Current Liabilities		
Long-term debt due within one year	25 760	16 106
Other long-term debt potentially due within one year	141 600	141 600
Short-term debt – primarily commercial paper	216 194	238 439
Accounts payable	246 051	234 905
Taxes accrued	202 777	178 119
Interest accrued	31 806	28 164
Dividends payable on common and preferred stocks	48 875	47 283
Accrued payroll, vacation and other	78 310	79 029
Total current liabilities	991 373	963 645
Other Liabilities		
Deferred income taxes	841 153	845 031
Deferred investment tax credits	161 513	173 838
Regulatory liabilities	242 787	200 517
Pension and other benefit obligations	115 737	92 514
Other long-term obligations and deferred income	65 816	73 397
Total other liabilities	1 427 066	1 385 297
Commitments and Contingent Liabilities (See Notes 14 and 15)		
Total	$6 228 585	$5 949 732

See Notes to Financial Statements on pages 34 to 49

(Dollar amounts in thousands)	Number of Shares Issued	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Cumulative Currency Translation Adjustments
Balance at Dec. 31, 1992	**62 598 360**	**$156 496**	**$370 819**	**$1 099 896**	**$ (5 113)**	
Net income				211 740		
Dividends declared:						
Cumulative preferred stock at required rates				(14 580)		
Common stock				(168 615)		
Issuances of common stock	4 281 217	10 703	176 296			
Preferred stock redemption and stock issuance costs			(3 345)	(1 069)		
Loan to ESOP to purchase shares					(15 000)	
Repayment of ESOP loan					9 226	
Balance at Dec. 31, 1993	**66 879 577**	**$167 199**	**$543 770**	**$1 127 372**	**$(10 887)**	
Net income				243 475		
Dividends declared:						
Cumulative preferred stock at required rates				(12 364)		
Common stock				(175 292)		
Issuances of common stock	42 567	106	1 342			
Stock issuance costs			(80)			
Tax benefit from stock options exercised			843			
Repayment of ESOP loan					7 897	
Currency translation adjustments						$3 586
Balance at Dec. 31, 1994	**66 922 144**	**$167 305**	**$545 875**	**$1 183 191**	**$ (2 990)**	**$3 586**
Net income				275 795		
Dividends declared:						
Cumulative preferred stock at required rates				(12 450)		
Common stock				(180 510)		
Issuances of common stock	1 253 790	3 135	53 051			
Stock issuance costs			(1)			
Tax benefit from stock options exercised			169			
Loan to ESOP to purchase shares					(15 000)	
Repayment of ESOP loan					7 333	
Currency translation adjustments						(1 098)
Balance at Dec. 31, 1995	**68 175 934**	**$170 440**	**$599 094**	**$1 266 026**	**$(10 657)**	**$2 488**

See Notes to Financial Statements on pages 34 to 49

(Thousands of dollars)	Dec. 31 1995	1994
Common Stockholders' Equity		
Common stock – authorized 160,000,000 shares of $2.50 par value;		
issued shares: 1995, 68,175,934; 1994, 66,922,144	**$ 170 440**	$ 167 305
Premium on common stock	**599 094**	545 875
Retained earnings	**1 266 026**	1 183 191
Leveraged common stock held by Employee Stock Ownership Plan (ESOP)		
– shares at cost: 1995, 229,154; 1994, 59,445	**(10 657)**	(2 990)
Currency translation adjustments – net	**2 488**	3 586
Total common stockholders' equity	**$2 027 391**	$1 896 967
Cumulative Preferred Stock – authorized 7,000,000 shares of $100 par value;		
outstanding shares: 1995 and 1994, 2,400,000		
Minnesota Company		
$3.60 series, 275,000 shares	**$27 500**	$27 500
4.08 series, 150,000 shares	**15 000**	15 000
4.10 series, 175,000 shares	**17 500**	17 500
4.11 series, 200,000 shares	**20 000**	20 000
4.16 series, 100,000 shares	**10 000**	10 000
4.56 series, 150,000 shares	**15 000**	15 000
6.80 series, 200,000 shares	**20 000**	20 000
7.00 series, 200,000 shares	**20 000**	20 000
Variable Rate series A, 300,000 shares	**30 000**	30 000
Variable Rate series B, 650,000 shares	**65 000**	65 000
Total	**240 000**	240 000
Premium on preferred stock	**469**	469
Total preferred stockholders' equity	**$ 240 469**	$ 240 469
Long-Term Debt		
First Mortgage Bonds Minnesota Company		
Series due:		
March 1, 1996, 6.2%	**$ 8 800***	$ 8 800*
Oct. 1, 1997, 5⅛%	**100 000**	100 000
Feb. 1, 1999, 5½%	**200 000**	200 000
Dec. 1, 2000, 5¾%	**100 000**	100 000
Oct. 1, 2001, 7⅛%	**150 000**	150 000
March 1, 2002, 7⅜%	**50 000**	50 000
Feb. 1, 2003, 7½%	**50 000**	50 000
April 1, 2003, 6⅜%	**80 000**	80 000
Dec. 1, 2005, 6⅛%	**70 000**	70 000
Dec. 1, 1994-2006, 6.60%	**21 100****	22 300**
March 1, 2011, Variable Rate	**13 700***	13 700*
July 1, 2019, 9⅛%		98 000
June 1, 2020, 9¾%		70 000
July 1, 2025, 7⅛%	**250 000**	
Total	**$1 093 600**	$1 012 800
Less redeemable bonds classified as current (see Note 7)	**(13 700)**	(13 700)
Less current maturities	**(10 100)**	(1 200)
Net	**$1 069 800**	$ 997 900

** Pollution control financing*

*** Resource recovery financing*

See Notes to Financial Statements on pages 34 to 49

(Thousands of dollars)	Dec. 31 1995	1994
Long-Term Debt – continued		
First Mortgage Bonds Wisconsin Company		
(less reacquired bonds: 1995, $3,365; 1994, $490)		
Series due:		
Oct. 1, 2003, 5¾%	$ 40 000	$ 40 000
April 1, 2021, 9⅛%	44 635	48 010
March 1, 2023, 7¼%	110 000	110 000
Total	194 635	198 010
Less current maturities		(2 910)
Net	$ 194 635	$ 195 100
Guaranty Agreements – Minnesota Company		
Series due:		
Feb. 1, 1994-2003, 5.41%	$ 5 700*	$ 5 900*
May 1, 1994-2003, 5.69%	24 250*	24 750*
Feb. 1, 2003, 7.40%	3 500*	3 500*
Total	33 450	34 150
Less current maturities	(700)	(700)
Net	$ 32 750	$ 33 450
Miscellaneous Long-Term Debt		
City of Becker Pollution Control Revenue Bonds – Series due		
Dec. 1, 2005, 7.25%	$ 9 000*	$ 9 000*
April 1, 2007, 6.80%	60 000*	60 000*
March 1, 2019, Variable Rate	27 900*	27 900*
Sept. 1, 2019, Variable Rate	100 000*	100 000*
Anoka County Resource Recovery Bond – Series due		
Dec. 1, 1994-2008, 7.06%	24 150**	25 150**
City of La Crosse, Resource Recovery Bond – Series due		
Nov. 1, 2011, 7¾%	18 600**	18 600**
Viking Gas Transmission Company Senior Notes – Series due		
Oct. 31, 2008, 6.4%	27 378	29 511
NRG Energy Center, Inc. (Minneapolis Energy Center)		
Senior Secured Notes – Series due June 15, 2013, 7.31%	79 326	81 498
United Power & Land Notes due		
March 31, 2000, 7.62%	8 542	9 375
Various Affordable Housing Project Notes due		
1994-2024, 1.0%-9.9%	20 696	7 710
Employee Stock Ownership Plan Bank Loan due		
1994-2002, Variable Rate	9 874	2 698
Other	8 967	10 736
Total	394 433	382 178
Less variable rate Becker bonds classified as current (See Note 7)	(127 900)	(127 900)
Less current maturities	(14 960)	(11 296)
Net	$ 251 573	$ 242 982
Unamortized discount on long-term debt – net	(6 472)	(6 078)
Total long-term debt	1 542 286	1 463 354
Total capitalization	$3 810 146	$3 600 790

* *Pollution control financing*

** *Resource recovery financing*

See Notes to Financial Statements on pages 34 to 49

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

System of Accounts Northern States Power Company, a Minnesota corporation (the Company), is predominantly a regulated public utility serving customers in Minnesota, North Dakota and South Dakota. Northern States Power Company, a Wisconsin corporation (the Wisconsin Company), a wholly owned subsidiary of the Company, is a regulated public utility serving customers in Wisconsin and Michigan. Another wholly owned subsidiary, Viking Gas Transmission Company (Viking), is a regulated natural gas transmission company that operates a 500-mile interstate natural gas pipeline. Consequently, the Company, the Wisconsin Company and Viking maintain accounting records in accordance with either the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) or those prescribed by state regulatory commissions, whose systems are the same in all material respects.

Principles of Consolidation The consolidated financial statements include all material companies in which NSP holds a controlling financial interest, including: the Wisconsin Company; NRG Energy, Inc. (NRG); Viking; Cenergy, Inc. (Cenergy), which changed its name to Cenerprise, Inc. effective Jan. 1, 1996; and Eloigne Company. As discussed in Note 3, NSP has investments in partnerships, joint ventures and projects for which the equity method of accounting is applied. Earnings from equity in international investments are recorded net of foreign income taxes. All significant intercompany transactions and balances have been eliminated in consolidation except for intercompany and intersegment profits for sales among the electric and gas utility businesses of the Company, the Wisconsin Company and Viking, which are allowed in utility rates. The Company and its subsidiaries collectively are referred to herein as NSP.

Revenues Revenues are recognized based on products and services provided to customers each month. Because utility customer meters are read and billed on a cycle basis, unbilled revenues (and related energy costs) are estimated and recorded for services provided from the monthly meter-reading dates to month-end.

The Company's rate schedules, applicable to substantially all of its utility customers, include cost-of-energy adjustment clauses, under which rates are adjusted to reflect changes in average costs of fuels, purchased energy and gas purchased for resale. The Company's rate schedules in Minnesota also include a rate adjustment clause, which is to be adjusted annually, to reflect changes in recovery of electric and gas deferred conservation program costs. As ordered by its primary regulator, Wisconsin Company retail rate schedules include a cost-of-energy adjustment clause for purchased gas but not for electric fuel and purchased energy. The biennial retail rate review process for Wisconsin electric operations considers changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment.

Utility Plant and Retirements Utility plant is stated at original cost. The cost of additions to utility plant includes contracted work, direct labor and materials, allocable overhead costs and allowance for funds used during construction. The cost of units of property retired, plus net removal cost, is charged to the accumulated provision for depreciation and amortization. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Allowance for Funds Used During Construction (AFC) AFC, a non-cash item, is computed by applying a composite pretax rate, representing the cost of capital used to finance utility construction activities, to qualified Construction Work in Progress (CWIP). The AFC rate was 6.0 percent in 1995, 5.0 percent in 1994 and 7.4 percent in 1993. The amount of AFC capitalized as a construction cost in CWIP is credited to other income (for equity capital) and interest charges (for debt capital). AFC amounts capitalized in CWIP are included in rate base for establishing utility service rates. In addition to construction-related amounts, AFC is also recorded to reflect returns on capital used to finance conservation programs.

Depreciation For financial reporting purposes, depreciation is computed by applying the straight-line method over the estimated useful lives of various property classes. The Company files with the Minnesota Public Utilities Commission (MPUC) an annual review of remaining lives for electric and gas production properties. The most recent studies, as approved by the MPUC, recommended a decrease of approximately $0.2 million and an increase of approximately $0.5 million for the 1995 and 1994 annual depreciation accruals, respectively.

Every five years, the Company also must file an average service life filing for transmission, distribution and general properties. The most recent filings approved by the MPUC were in 1994 for general plant and in 1993 for all other facilities. Depreciation provisions, as a percentage of the average balance of depreciable utility property in service, were 3.64 percent in 1995, 3.55 percent in 1994 and 3.47 percent in 1993.

Decommissioning As discussed in Note 14, NSP currently is recording the future costs of decommissioning the Company's nuclear generating plants through annual depreciation accruals. The provision for the estimated decommissioning costs has been calculated using an annuity approach designed to provide for full expense accrual (with full rate recovery) of the future decommissioning costs, including reclamation and removal, over the estimated operating lives of the Company's nuclear plants. The Financial Accounting Standards Board (FASB) has proposed new accounting standards expected to go into effect in 1997. The standards would require the full accrual of nuclear plant decommissioning and certain other site exit obligations beginning in 1997. (See Note 14 for more discussion of this proposed standard.)

Nuclear Fuel Expense The original cost of nuclear fuel is amortized to fuel expense based on energy expended. Nuclear fuel expense also includes assessments from the U.S. Department of Energy (DOE) for costs of future fuel disposal and DOE facility decommissioning, as discussed in Note 14.

Environmental Costs Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. When a single estimate of the liability cannot be determined, the low end of the estimated range is accrued. Costs are charged to expense or deferred as a regulatory asset based on expected recovery in future rates, if they relate to the remediation of conditions caused by past operations, or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted

amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where NSP has been designated as one of several potentially responsible parties, the amount accrued represents NSP's estimated share of the cost. NSP intends to treat any future costs incurred related to decommissioning and restoration of its non-nuclear power plants and substation sites, where operation may extend indefinitely, as a capitalized removal cost of retirement in utility plant. Depreciation expense levels currently recovered in rates include a provision for an estimate of removal costs (based on historical experience).

Income Taxes NSP records income taxes in accordance with Statement of Financial Accounting Standards (SFAS) No. 109 – Accounting for Income Taxes. Under the liability method required by SFAS No. 109, income taxes are deferred for all temporary differences between pretax financial and taxable income and between the book and tax bases of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by law to be in effect when the temporary differences reverse. Due to the effects of regulation, current income tax expense is provided for the reversal of some temporary differences previously accounted for by the flow-through method. Also, regulation has created certain regulatory assets and liabilities related to income taxes, as summarized in Note 10. NSP's policy for income taxes related to international operations is discussed in Note 9.

Investment tax credits are deferred and amortized over the estimated lives of the related property.

Foreign Currency Translation The local currencies are generally the functional currency of NSP's foreign operations. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. The resulting currency translation adjustments are accumulated and reported as a separate component of stockholders' equity. Income, expense and cash flows are translated at weighted-average rates of exchange for the period.

Exchange gains and losses that result from foreign currency transactions (e.g. converting cash distributions made in one currency to another) are included in the results of operations as a component of equity in earnings of unconsolidated affiliates. Through Dec. 31, 1995, NSP had not experienced any material translation gains or losses from foreign currency transactions that have occurred since the respective foreign investment dates.

Derivative Financial Instruments NSP's policy is to hedge foreign currency denominated investments as they are made to preserve their U.S. dollar value, where appropriate hedging instruments are available. NRG has entered into currency hedging transactions through the use of forward foreign currency exchange agreements. Gains and losses on these agreements offset the effect of foreign currency exchange rate fluctuations on the valuation of the investments underlying the hedges. Hedging gains and losses, net of income tax effects, are reported with other currency translation adjustments as a separate component of stockholders' equity. NRG is not hedging currency translation adjustments related to future operating results. NSP does not speculate in foreign currencies. A second derivative arrangement is the use of natural gas futures contracts by Cenergy to manage the risk of gas price fluctuations. The cost or benefit of natural gas futures contracts is recorded when related sales commitments are fulfilled as a component of Cenergy's non-regulated operating expenses. NSP does not speculate in natural gas futures. A third derivative instrument used by NSP is interest rate swaps that convert fixed rate debt to variable rate debt. The cost or benefit of the interest rate swap agreements is recorded as a component of interest expense. None of these three derivative financial instruments is reflected on NSP's balance sheet.

Use of Estimates In recording transactions and balances resulting from business operations, NSP uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, tax provisions, uncollectible accounts, environmental loss contingencies, unbilled revenues and actuarially determined benefit costs. As better information becomes available (or actual amounts are determinable), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. Recent changes in interest rates have resulted in changes to actuarial assumptions used in the benefit cost calculations for postretirement benefits. Also, the depreciable lives of certain plant assets are reviewed and, if appropriate, revised each year, as discussed previously. (See Notes 8, 14 and 15 for more information on the effects of these changes in estimates.)

Cash Equivalents NSP considers investments in certain debt instruments (primarily commercial paper) with an original maturity to NSP of three months or less at the time of purchase to be cash equivalents.

Regulatory Deferrals As regulated utilities, the Company, the Wisconsin Company and Viking account for certain income and expense items under the provisions of SFAS No. 71 – Accounting for the Effects of Regulation. In doing so, certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates. Likewise, certain credits that otherwise would be reflected as income are deferred as regulatory liabilities based on expected flowback to customers in future rates. Management's expected recovery of deferred costs and expected flowback of deferred credits are generally based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with ratemaking treatment established by regulators. Note 10 describes the nature and amounts of these regulatory deferrals.

Other Assets The purchase of various non-regulated entities from 1993-1995 at a price exceeding the underlying fair value of net assets acquired resulted in recorded goodwill of $20.3 million ($19.0 million net of accumulated amortization) at Dec. 31, 1995. This goodwill and other intangible assets acquired are being amortized using the straight-line method over periods of 15 to 30 years. NSP periodically evaluates the recovery of goodwill based on an analysis of estimated undiscounted future cash flows.

Intangible and other assets also include deferred financing costs (net of amortization) of approximately $11.8 million at Dec. 31, 1995. These costs are being amortized over the remaining maturity period of the related debt.

Reclassifications Certain reclassifications have been made to the 1994 and 1993 financial statements to conform with the 1995 presentation. These reclassifications had no effect on net income or earnings per share.

2. ACCOUNTING CHANGES

Postemployment Benefits Effective Jan. 1, 1994, NSP adopted the provisions of SFAS No. 112 – Employers' Accounting for Postemployment Benefits. This standard required the accrual of certain postemployment costs, such as injury compensation and severance, that are payable in the future. The Company's pre-1994 liability of approximately $9.4 million (8 cents per share) was expensed in 1994.

Postretirement Benefits As discussed in Note 8, NSP changed its accounting for postretirement medical and death benefits in 1993. Due to rate recovery of the expense increases, the change had an immaterial effect on net income. Of the 1993 cost increases due to adoption of SFAS No. 106, about $12 million was deferred to be amortized over rate recovery periods in 1994-1996. In 1994, administrative and general expenses increased by approximately $16 million due to the full recognition of accrued SFAS No. 106 costs, including amounts deferred from 1993.

3. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Through its non-regulated subsidiaries, NSP has investments in various international and domestic energy projects and domestic affordable housing and real estate projects. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents NSP from exercising a controlling influence over operating and financial policies of the projects. Under this method, equity in the pretax income or losses of domestic partnerships and in the net income or losses of international projects is reflected as Equity in Earnings of Unconsolidated Affiliates. A summary of NSP's significant equity-method investments is as follows:

Name	Geographic Area	Economic Interest	Purchased or Placed in Service
Various Independent Power Production Facilities	U.S.A.	45%-50%	July 1991-December 1994
Affordable Housing – Limited Partnerships	U.S.A.	20%-99%	April 1993-December 1995
Rosebud SynCoal Partnership	U.S.A.	50%	August 1993
MIBRAG Mining and Power Generation	Europe	33.3%	January 1994
Gladstone Power Station	Australia	37.5%	March 1994
Scudder Latin American Trust for Independent Power Energy Projects	Latin America	25%	June 1993
Schkopau Power Station	Europe	20.6%	Under Construction

Investments in the MIBRAG and Gladstone projects in 1994 resulted in an increase in the equity in earnings from unconsolidated affiliates of approximately $26 million in 1994.

Summarized Financial Information of Unconsolidated Affiliates Summarized financial information for these projects, including interests owned by NSP and other parties, was as follows (as of and for the years ended Dec. 31, 1995 and 1994):

Financial Position *(Millions of dollars)*	1995	1994
Current Assets	$ 762.1	$ 514.9
Other Assets	2 631.9	1 593.8
Total Assets	$3 394.0	$2 108.7
Current Liabilities	$ 295.5	$ 159.6
Other Liabilities	2 290.2	1 480.0
Equity	808.3	469.1
Total Liabilities and Equity	$3 394.0	$2 108.7
NSP's Equity Investment in Unconsolidated Affiliates	$266.0	$179.1

Results of Operations *(Millions of dollars)*	1995	1994
Operating Revenues	$790.2	$778.4
Operating Income	$154.2	$128.8
Net Income	$160.2	$117.0

4. CUMULATIVE PREFERRED STOCK

The Company has two series of adjustable rate preferred stock. The dividend rates are calculated quarterly and are based on prevailing rates of certain taxable government debt securities indices. At Dec. 31, 1995, the annualized dividend rates were $5.50 for both series A and series B.

At Dec. 31, 1995, the various preferred stock series were callable at prices per share ranging from $102.00 to $103.75, plus accrued dividends. In 1993, the Company redeemed all 350,000 shares of its $7.84 series Cumulative Preferred Stock at $103.12 per share.

5. COMMON STOCK AND INCENTIVE STOCK PLANS

The Company's Articles of Incorporation and First Mortgage Indenture provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 1995, the Company could have paid, without restrictions, additional cash dividends of more than $1 billion on common stock.

NSP has an Executive Long-Term Incentive Award Stock Plan that permits granting non-qualified stock options. The options currently granted may be exercised one year from the date of grant and are exercisable thereafter for up to nine years. The plan also allows certain employees to receive restricted stock and other performance awards. Performance awards are valued in dollars, but paid in shares based on the market price at the time of payment. Transactions under the various incentive stock programs, which may result in the issuance of new shares, were as follows:

Stock Awards

(Thousands of shares)	1995	1994	1993
Outstanding Jan. 1	782.4	537.1	528.7
Options granted	278.0	304.0	196.9
Other stock awards		.2	9.5
Options and awards exercised	(63.8)	(42.6)	(174.3)
Options and awards forfeited	(6.5)	(16.1)	(22.2)
Other	(.1)	(.2)	(1.5)
Outstanding at Dec. 31	990.0	782.4	537.1
Option price ranges:			
Unexercised at Dec. 31	$33.25-$45.50	$33.25-$43.50	$33.25-$43.50
Exercised during the year	$33.25-$43.50	$33.25-$43.50	$33.25-$40.94

Using the treasury stock method of accounting for outstanding stock options, the weighted average number of shares of common stock outstanding for the calculation of primary earnings per share includes any dilutive effects of stock options and other stock awards as common stock equivalents. The differences between shares used for primary and fully diluted earnings per share were not material.

6. SHORT-TERM BORROWINGS

NSP has approximately $282 million of commercial bank credit lines under commitment fee arrangements. These credit lines make short-term financing available in the form of bank loans and support for commercial paper sales. There were no borrowings against these credit lines at Dec. 31, 1995, and approximately $3.6 million of such borrowings, with interest payable at 9.75 percent, at Dec. 31, 1994. However, $9.6 million in letters of credit were outstanding, which reduced the available credit lines at Dec. 31, 1995.

At Dec. 31, 1995 and 1994, the Company had $215.6 million and $234.8 million, respectively, in short-term commercial paper borrowings outstanding. The weighted average interest rates on all short-term borrowings as of Dec. 31, 1995, and Dec. 31, 1994, were 5.7 percent and 6.1 percent, respectively.

7. LONG-TERM DEBT

The annual sinking-fund requirements of the Company's and the Wisconsin Company's First Mortgage Indentures are the amounts necessary to redeem 1 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding those series issued for pollution control and resource recovery financings, and excluding certain other series totaling $990 million. The Company may, and has, applied property additions in lieu of cash payments on all series, as permitted by its First Mortgage Indenture. The Wisconsin Company also may apply property additions in lieu of cash on all series as permitted by its First Mortgage Indenture. Except for minor exclusions, all real and personal property of the Company and the Wisconsin Company is subject to the liens of the first mortgage indentures. Other debt securities are secured by a lien on the related real or personal property, as indicated on the Consolidated Statements of Capitalization.

The Company's First Mortgage Bonds Series due March 1, 2011, and the City of Becker Pollution Control Revenue Bonds Series due March 1, 2019, and Sept. 1, 2019, have variable interest rates, which currently change at various periods up to 270 days, based on prevailing rates for certain commercial paper securities or similar issues. The interest rates applicable to these issues averaged 5.2 percent, 3.7 percent and 3.8 percent, respectively, at Dec. 31, 1995. The 2011 series bonds are redeemable upon seven days notice at the option of the bondholder. The Company also is potentially liable for repayment of the 2019 Series Becker Bonds when the bonds are tendered, which occurs each time the variable interest rates change. The principal amount of all three series of these variable rate bonds outstanding represents potential short-term obligations and, therefore, is reported under current liabilities on the balance sheet.

Maturities and sinking-fund requirements on long-term debt are: 1996, $25,760,000; 1997, $111,553,000; 1998, $14,457,000; 1999, $210,909,000; and 2000, $115,982,000.

8. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

NSP offers the following benefit plans to its benefit employees, of whom approximately 43 percent are represented by five local labor unions under a collective-bargaining agreement, which expires Dec. 31, 1996.

Pension Benefits NSP has a non-contributory, defined benefit pension plan that covers substantially all employees. Benefits are based on a combination of years of service, the employee's highest average pay for 48 consecutive months and Social Security benefits.

It is the Company's policy to fully fund the actuarially determined pension costs recognized for ratemaking purposes, subject to the limitations under applicable employee benefit and tax laws. Plan assets principally consist of common stock of public companies, corporate bonds and U.S. government securities. The funded status of NSP's pension plan as of Dec. 31 is as follows:

(Thousands of dollars)	1995	1994
Actuarial present value of benefit obligation:		
Vested	$ 686 403	$ 571 254
Non-vested	155 177	120 420
Accumulated benefit obligation	$ 841 580	$ 691 674
Projected benefit obligation	$1 039 981	$ 836 957
Plan assets at fair value	1 456 530	1 165 584
Plan assets in excess of projected benefit obligation	(416 549)	(328 627)
Unrecognized prior service cost	(20 805)	(21 538)
Unrecognized net actuarial gain	452 699	370 289
Unrecognized net transitional asset	615	691
Net pension liability recorded	$ 15 960	$ 20 815

For regulatory purposes, the Company's pension expense is determined and recorded under the aggregate-cost method. As required by SFAS No. 87 – Employers' Accounting for Pensions, the difference between the pension costs recorded for ratemaking purposes and the amounts determined under SFAS No. 87 is recorded as a regulatory liability on the balance sheet. Net annual periodic pension cost includes the following components:

(Thousands of dollars)	1995	1994	1993
Service cost-benefits earned during the period	**$24 429**	$27 536	$25 015
Interest cost on projected benefit obligation	**69 742**	65 107	71 075
Actual return on assets	**(344 837)**	(12 668)	(152 019)
Net amortization and deferral	**240 458**	(82 114)	66 299
Net periodic pension cost determined under SFAS No. 87	**(10 138)**	(2 139)	10 370
Additional costs recognized due to actions of regulators	**10 454**	3 922	5 117
Net periodic pension cost recognized for ratemaking	**$ 316**	$ 1 783	$15 487

The weighted average discount rate used in determining the actuarial present value of the projected obligation was 7 percent in 1995 and 8 percent in 1994. The rate of increase in future compensation levels used in determining the actuarial present value of the projected obligation was 5 percent in 1995 and 1994. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 87 was 9 percent for 1995 and 8 percent for 1994 and 1993. Assumption changes decreased 1995 pension costs (determined under SFAS No. 87) by approximately $21.5 million. Assumption changes are expected to increase 1996 pension costs (determined under SFAS No. 87) by approximately $13.6 million. Because the Company's pension expense is determined under the aggregate-cost method (not SFAS No. 87) for regulatory and financial reporting purposes, the effects of regulation prevent the majority of these assumption changes from affecting earnings.

Postretirement Health Care NSP has a contributory health and welfare benefit plan that provides health care and death benefits to substantially all employees after their retirement. The plan is intended to provide for sharing the costs of retiree health care between NSP and retirees. For employees retiring after Jan. 1, 1994, a six-year cost-sharing strategy was implemented with retirees paying 15 percent of the total cost of health care in 1994, increasing to a total of 40 percent in 1999.

Effective Jan. 1, 1993, NSP adopted the provisions of SFAS No. 106 – Employers' Accounting for Postretirement Benefits Other Than Pensions. SFAS No. 106 requires the actuarially determined obligation for postretirement health care and death benefits to be fully accrued by the date employees attain full eligibility for such benefits, which is generally when they reach retirement age. This is a significant change from NSP's pre-1993 policy of recognizing benefit costs on a cash basis after retirement. In conjunction with the adoption of SFAS No. 106, NSP elected to amortize on a straight-line basis over 20 years the unrecognized accumulated postretirement benefit obligation (APBO) of $215.6 million for current and future retirees. This obligation considered 1994 plan design changes, including Medicare integration, increased retiree cost sharing and managed indemnity measures not in effect in 1993.

Before 1993, NSP funded payments for retiree benefits internally. While NSP generally prefers to continue using internal funding of benefits paid and accrued, significant levels of external funding, including the use of tax-advantaged trusts, have been required by NSP's regulators, as discussed below. Plan assets held in such trusts as of Dec. 31, 1995, consisted of investments in equity mutual funds and cash equivalents. The funded status of NSP's health care plan as of Dec. 31 is as follows:

(Millions of dollars)	1995	1994
APBO:		
Retirees	**$145.8**	$132.2
Fully eligible plan participants	**24.4**	21.5
Other active plan participants	**116.8**	79.4
Total APBO	**287.0**	233.1
Plan assets at fair value	**11.6**	8.0
APBO in excess of plan assets	**275.4**	225.1
Unrecognized net actuarial gain (loss)	**(40.4)**	2.3
Unrecognized transition obligation	**(183.2)**	(194.0)
Net benefit obligation recorded	**$ 51.8**	$ 33.4

The assumed health care cost trend rates used in measuring the APBO at Dec. 31, 1995 and 1994, respectively, were 10.4 and 11.0 percent for those under age 65, and 7.3 and 7.5 percent for those over age 65. The assumed cost trend rates are expected to decrease each year until they reach 5.5 percent for both age groups in the year 2004, after which they are assumed to remain constant. A 1 percent increase in the assumed health care cost trend rate for each year would increase the APBO by approximately 15 percent as of Dec. 31, 1995. Service and interest cost components of the net periodic postretirement cost would increase by approximately 17 percent with a similar 1 percent increase in the assumed health care cost trend rate. The assumed discount rate used in determining the APBO was 7 percent for Dec. 31, 1995, 8 percent for Dec. 31, 1994, and 7 percent for Dec. 31, 1993, compounded annually. The assumed long-term rate of return on assets used for cost determinations under SFAS No. 106 was 8 percent for 1995 and 1994. Assumption changes decreased 1994 costs by approximately $2.1 million and decreased 1995 costs by approximately $2.0 million. The effect of the changes in 1996 is expected to be a cost increase of approximately $2.1 million.

The net annual periodic postretirement benefit cost recorded consists of the following components:

(Millions of dollars)	1995	1994	1993
Service cost-benefits earned during the year	**$ 5.2**	$ 5.0	$ 4.4
Interest cost (on service cost and APBO)	**19.2**	16.1	17.5
Actual return on assets	**(1.0)**	(.2)	(.1)
Amortization of transition obligation	**10.8**	10.8	10.8
Net amortization and deferral	**0.4**	(.3)	.1
Net periodic postretirement health care cost under SFAS No. 106	**34.6**	31.4	32.7
Costs recognized (deferred) due to actions of regulators	**4.0**	4.1	(12.1)
Net periodic postretirement health care cost recognized for ratemaking	**$38.6**	$35.5	$20.6

Regulators for NSP's retail and wholesale customers in Minnesota, Wisconsin and North Dakota have allowed full recovery of increased benefit costs under SFAS No. 106, effective in 1993. Increased 1993 accrual costs for Minnesota retail customers are being amortized over the years 1994 through 1996, consistent with approved rate recovery. External funding was required by Minnesota and Wisconsin retail regulators to the extent it is tax advantaged; funding began for Wisconsin in 1993 and must begin by the next general rate filing for Minnesota. For wholesale ratemaking, the FERC has required external funding for all benefits paid and accrued under SFAS No. 106.

ESOP NSP has a leveraged Employee Stock Ownership Plan (ESOP) that covers substantially all employees. Employer contributions to this non-contributory, defined contribution plan are generally made to the extent NSP realizes a tax savings on its income statement from dividends paid on certain shares held by the ESOP. Contributions to the ESOP in 1995, 1994 and 1993, which represent compensation expense, were $5,059,000, $5,695,000 and $6,281,000, respectively. ESOP contributions have no material effect on NSP earnings because the contributions (net of tax) are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Leveraged shares held by the ESOP are allocated to participants when dividends on stock held by the plan are used to repay ESOP loans. NSP's ESOP held 5.7 million and 5.4 million shares of the Company's common stock as of Dec. 31, 1995 and 1994, respectively. An average of 221,066 and 111,845 uncommitted leveraged ESOP shares were excluded from earnings-per-share calculations in 1995 and 1994, respectively. The fair value of NSP's leveraged ESOP shares approximated cost at Dec. 31, 1995.

401(k) NSP has a contributory, defined contribution Retirement Savings Plan, which complies with section 401(k) of the Internal Revenue Code and covers substantially all employees. Since 1994, NSP has been matching specified amounts of employee contributions to this plan. NSP's matching contributions were $3.7 million in 1995 and $2.6 million in 1994.

9. INCOME TAXES

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The reasons for the difference are as follows:

	1995	1994	1993
Federal statutory rate	**35.0 %**	35.0 %	35.0 %
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	**5.1 %**	5.9 %	6.1 %
Tax credits recognized	**(3.4)%**	(3.5)%	(2.8)%
Equity income from unconsolidated international affiliates	**(2.5)%**	(2.5)%	0.0 %
Regulatory differences – utility plant items	**1.0 %**	0.5 %	1.3 %
Other – net	**0.4 %**	(0.7)%	(1.4)%
Effective income tax rate	**35.6 %**	34.7 %	38.2 %
(Thousands of dollars)			
Income taxes are comprised of the following expense (benefit) items:			
Included in utility operating expenses:			
Current federal tax expense	**$137 011**	$108 652	$92 099
Current state tax expense	**33 359**	34 823	25 787
Deferred federal tax expense	**(12 019)**	(3 450)	15 010
Deferred state tax expense	**(2 396)**	(1 606)	4 431
Deferred investment tax credits	**(8 807)**	(9 191)	(8 981)
Total	**147 148**	129 228	128 346
Included in other income (expense):			
Current federal tax expense	**5 481**	3 959	7 853
Current state tax expense	**1 629**	923	2 289
Current foreign tax expense	**233**	219	
Current federal tax credits	**(5 292)**	(3 548)	(321)
Deferred federal tax expense	**2 646**	(835)	(6 736)
Deferred state tax expense	**693**	(209)	(449)
Deferred investment tax credits	**(310)**	(310)	(242)
Total	**5 080**	199	2 394
Total income tax expense	**$152 228**	$129 427	$130 740

Income before income taxes includes net foreign equity income of $32.3 and $25.9 million in 1995 and 1994, respectively. NSP's management intends to reinvest the earnings of foreign operations indefinitely. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on the earnings of foreign subsidiary companies. The cumulative amount of undistributed earnings of foreign subsidiaries upon which no U.S. income taxes or foreign withholding taxes have been provided is approximately $61.6 million at Dec. 31, 1995. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in whole or in part by foreign tax credits. Thus, it is impracticable to estimate the amount of tax that might be payable.

The components of NSP's net deferred tax liability (current and non-current portions) at Dec. 31 were:

(Thousands of dollars)	1995	1994
Deferred tax liabilities:		
Difference between book and tax bases of property	**$ 866 784**	$ 843 872
Regulatory assets	**124 910**	120 329
Tax benefit transfer leases	**59 579**	76 775
Other	**13 338**	7 854
Total deferred tax liabilities	**$1 064 611**	$1 048 830
Deferred tax assets:		
Regulatory liabilities	**$ 96 935**	$ 80 383
Deferred investment tax credits	**61 911**	65 812
Deferred compensation, vacation and other accrued liabilities not currently deductible	**57 209**	50 572
Other	**22 658**	18 110
Total deferred tax assets	**$ 238 713**	$ 214 877
Net deferred tax liability	**$ 825 898**	$ 833 953

10. REGULATORY ASSETS AND LIABILITIES

The following summarizes the individual components of unamortized regulatory assets and liabilities shown on the Consolidated Balance Sheets at Dec. 31:

(Thousands of dollars)	Amortization Period	1995	1994
AFC recorded in plant on a net-of-tax basis*	Plant Lives	**$146 662**	$155 102
Conservation and energy management programs*	Up to 10 Years	**98 570**	76 902
Losses on reacquired debt	Term of New Debt	**63 209**	52 514
Environmental costs	Up to 15 Years	**45 018**	47 779
Deferred postretirement benefit costs	3-15 Years	**5 568**	9 930
Unrecovered purchased gas costs	1-2 Years	**5 932**	7 601
State commission accounting adjustments*	Plant Lives	**7 221**	5 544
Other	Various	**2 032**	2 204
Total regulatory assets		**$374 212**	$357 576
Excess deferred income taxes collected from customers		**$ 83 066**	$ 75 277
Investment tax credit deferrals		**104 371**	110 831
Unrealized gains from decommissioning investments		**26 374**	1 412
Pension costs		**21 508**	11 054
Fuel costs and other		**7 468**	1 943
Total regulatory liabilities		**$242 787**	$200 517

* *Earns a return on investment in the ratemaking process.*

11. FINANCIAL INSTRUMENTS

Fair Values The estimated Dec. 31 fair values of NSP's recorded financial instruments are as follows:

(Thousands of dollars)	1995		1994	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Cash, cash equivalents and short-term investments	**$28 943**	**$28 943**	$ 41 947	$41 947
Long-term decommissioning investments	**$203 625**	**$203 625**	$145 467	$145 467
Long-term debt, including current portion	**$1 709 646**	**$1 781 066**	$1 621 060	$1 540 595

For cash, cash equivalents and short-term investments, the carrying amount approximates fair value because of the short maturity of those instruments. The fair values of the Company's long-term investments in an external nuclear decommissioning fund are estimated based on quoted market prices for those or similar investments. The fair value of NSP's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates offered to NSP for debt of the same remaining maturities.

Derivatives NRG has entered into six forward foreign currency exchange contracts with counterparties to hedge exposure to currency fluctuations to the extent permissible by hedge accounting requirements. Pursuant to these contracts, transactions have been executed that are designed to protect the economic value in U.S. dollars of NRG's equity investments and retained earnings, denominated in Australian dollars and German deutsche marks (DM). NRG's forward foreign currency exchange contracts, in the notional amount of $119 million, hedge approximately $123 million of foreign currency denominated assets, and in the notional amount of $47 million, hedge approximately $64 million of foreign currency denominated retained earnings at Dec. 31, 1995. Because the effects of both currency translation adjustments to foreign investments and currency hedge instrument gains and losses are recorded on a net basis in stockholders' equity (not earnings), the impact of significant changes in currency exchange rates on these items would have an immaterial effect on NSP's financial condition and results of operations. The contracts required cash collateral balances of $5.9 million at Dec. 31, 1995, which are reflected as other current assets on NSP's balance sheet. The contracts terminate in 1998 through 2005 and require foreign currency interest payments by either party during each year of the contract. If the contracts had been terminated at Dec. 31, 1995, $5.2 million would have been payable by NRG for currency exchange rate changes to date. Management believes NRG's exposure to credit risk due to non-performance by the counterparties to its forward exchange contracts is not significant, based on the investment grade rating of the counterparties.

Cenergy has entered into natural gas futures contracts in the notional amount of $11.3 million at Dec. 31, 1995. The original contract terms range from one month to three years. The contracts are intended to mitigate risk from fluctuations in the price of natural gas that will be required to satisfy sales commitments for future deliveries to customers in excess of Cenergy's natural gas reserves. Cenergy's futures contracts hedge $11.5 million in anticipated natural gas sales in 1996-1997. Margin balances of $2.3 million at Dec. 31, 1995, were maintained on deposit with brokers and recorded as cash and cash equivalents on NSP's balance sheet. The counterparties to the futures contracts are the New York Mercantile Exchange and major gas pipeline operators. Management believes that the risk of non-performance by these counterparties is not significant. If the contracts had been terminated at Dec. 31, 1995, $0.6 million would have been payable to Cenergy for natural gas price fluctuations to date.

NSP has three interest rate swap agreements with notional amounts totalling $320 million. These swaps were entered into in conjunction with first mortgage bonds. As summarized below, these agreements effectively convert the interest costs of these debt issues from fixed to variable rates based on six-month London Interbank Offered Rates (LIBOR), with the rates changing semiannually.

Series	Notional Amount *(millions of dollars)*	Term of Swap Agreement	Net Effective Interest Cost at Dec. 31, 1995
5¼% Series due Oct. 1, 1997	$100	Maturity	5.94%
5½% Series due Feb. 1, 1999	$200	Maturity	5.36%
7¼% Series due March 1, 2023	$20	March 1, 1998	8.03%

Market risks associated with these agreements result from short-term interest rate fluctuations. Credit risk related to non-performance of the counterparties is not deemed significant, but would result in NSP terminating the swap transaction and recognizing a gain or loss, depending on the fair market value of the swap. The interest rate swaps serve to hedge the interest rate risk associated with fixed rate debt in a declining interest rate environment. This hedge is produced by the tendency for changes in the fair market value of the swap to be offset by changes in the present value of the liability attributable to the fixed rate debt issued in conjunction with the interest rate swaps. If the interest rate swaps had been discontinued on Dec. 31, 1995, the present value benefit to NSP would have been $2.8 million, which is partially offset by an increase in the present value of the related debt of $0.9 million above carrying value.

Letters of Credit NSP uses letters of credit to provide financial guarantees for certain operating obligations, including NSP workers' compensation benefits and ash disposal site costs, and Cenergy natural gas purchases. At Dec. 31, 1995, letters of credit of $46.7 million were outstanding. Generally, the letters of credit have terms of one year and are automatically renewed, unless prior written notice of cancellation is provided to NSP and the beneficiary by the issuing bank. The contract amounts of these letters of credit approximate their fair value and are subject to fees competitively determined in the marketplace.

12. DETAIL OF CERTAIN INCOME AND EXPENSE ITEMS

Administrative and general (A&G) expense for utility operations consists of the following:

(Thousands of dollars)	**1995**	1994	1993
A&G salaries and wages	**$ 48 437**	$ 49 726	$ 51 601
Postretirement medical and injury compensation benefits	**34 112**	41 901	14 995
Other benefits – all utility employees	**47 167**	38 792	51 860
Information technology, facilities and administrative support	**31 863**	29 751	30 504
Insurance and claims	**13 969**	16 771	16 165
Other	**10 599**	11 055	11 492
Total	**$186 147**	$187 996	$176 617

Other income (deductions) – net consist of the following:

(Thousands of dollars)	**1995**	1994	1993
Non-regulated operations:			
Operating revenues and sales	**$313 082**	$241 827	$90 531
Operating expenses	**327 894***	241 480*	81 480
Pretax operating income**	**(14 812)**	347	9 051
Interest and investment income	**11 953**	10 839	4 522
Charitable contributions	**(5 314)**	(5 037)	(4 752)
Environmental and regulatory contingencies	**1 027**	(4 568)	(100)
Other – net (excluding income taxes)	**(829)**	(5 267)	(739)
Total – net income (expense)	**$ (7 975)**	$ (3 686)	$ 7 982

**Includes non-regulated energy project write-downs of $5.0 million in 1995 and $5.0 million in 1994.*

***See "Operating Results" on page 54 for a summary of the total operating results of non-regulated businesses.*

13. JOINT PLANT OWNERSHIP

The Company is a participant in a jointly owned 855-megawatt coal-fired electric generating unit, Sherburne County generating station unit No. 3 (Sherco 3), which began commercial operation Nov. 1, 1987. Undivided interests in Sherco 3 have been financed and are owned by the Company (59 percent) and Southern Minnesota Municipal Power Agency (41 percent). The Company is the operating agent under the joint ownership agreement. The Company's share of related expenses for Sherco 3 since commercial operations began are included in Utility Operating Expenses. The Company's share of the gross cost recorded in Utility Plant at Dec. 31, 1995 and 1994, was $585,625,000 and $585,783,000, respectively. The corresponding accumulated provisions for depreciation were $150,022,000 and $132,092,000.

14. NUCLEAR OBLIGATIONS

Fuel Disposal NSP is responsible for the temporary storage of used nuclear fuel from the Company's nuclear generating plants. Under a contract with the Company, the DOE is obligated to assume the responsibility for permanent storage or disposal of NSP's used nuclear fuel. The Company has been funding its portion of the DOE's permanent disposal program since 1981. Funding took place through an internal sinking fund until 1983, when the DOE began assessing fuel disposal fees under the Nuclear Waste Policy Act of 1982 based

on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. The cumulative amount of such assessments from the DOE to NSP through Dec. 31, 1995, is $230.8 million. Currently, it is not determinable if the amount and method of the DOE's assessments to all utilities will be sufficient to fully fund the DOE's permanent storage or disposal facility.

The DOE has stated in statute and by contract that a permanent storage or disposal facility would be ready to accept used nuclear fuel by 1998. Accordingly, NSP has been providing, with regulatory and legislative approval, its own temporary on-site storage facilities at its Monticello and Prairie Island nuclear plants, with a capacity sufficient for used fuel from the plants until at least that date. Recent indications from the DOE are that a permanent federal facility will not be ready to accept used fuel from utilities until approximately 2010. In 1994, the Company and 13 other major utilities filed a lawsuit against the DOE in an attempt to clarify the DOE's obligation to accept spent nuclear fuel beginning in 1998. The primary purpose of the lawsuit is to insure the Company and its customers receive timely storage of used nuclear fuel. The lawsuit was argued before the United States Circuit Court of Appeals for the District of Columbia on Jan. 17, 1996, and a decision is expected in three to six months from the time of argument. In 1995, the DOE published its "Final Interpretation of Nuclear Waste Acceptance Issues" in the Federal Register. In this notice, the DOE concluded that it has neither an unconditional obligation to accept spent nuclear fuel by 1998 nor any authority to provide interim storage. Because of the DOE's inadequate progress to provide a permanent repository and its disavowal of its obligation, the Minnesota Department of Public Service is investigating whether continued payments to fund the DOE's permanent disposal program is prudent use of ratepayer money. The outcome of this investigation is unknown at this time. In the meantime, NSP is investigating all of its alternatives for used fuel storage until a DOE facility is available. When on-site temporary storage at NSP's nuclear plants reaches approved capacity, the Company could seek interim storage at a contracted private facility. The Company received Minnesota legislative approval in 1994 for additional on-site storage facilities at its Prairie Island plant, provided the Company satisfies certain requirements. Seventeen dry cask containers, each of which can store approximately one-half year's used fuel, can become available as follows: five immediately in 1994; four more in 1996 if an application for an alternative storage site is filed, an effort to locate such a site is made and 100 megawatts of wind generation is available or contracted for construction; and the final eight in 1999, unless the specified alternative site is not operational or under construction, certain resource commitments are not met, or the Minnesota Legislature revokes its approval. (See additional discussion of legislative commitments in Note 15.) NSP has loaded used fuel into three of the dry cask containers as of Dec. 31, 1995. With the dry cask storage facilities approved in 1994 for the Prairie Island nuclear generating plant, the Company believes it has adequate storage capacity to continue operation of its nuclear plants until at least 2002 and 2003 for Prairie Island Units 1 and 2, respectively. The Monticello nuclear plant has storage capacity to continue operations until 2010. Storage availability to permit operation beyond these dates is not assured at this time.

Two alternatives to on-site storage of used fuel are currently under consideration. As discussed in Note 15, the Company is investigating alternative sites in Goodhue County, Minnesota, for interim used nuclear fuel storage. Also, the Company is leading a consortium working with the Mescalero Apache Tribe to establish a private facility for interim storage of used nuclear fuel on the Tribe's reservation in New Mexico. A core group of more than 20 United States nuclear utilities has agreed to support the construction and operation of the Mescalero interim storage site. Work on the project is under way in several areas, including environmental assessment, facility design and drafting the detailed contracts that will govern the construction and operation of the site. An architect engineering firm and an environmental contractor have been retained to perform the environmental and licensing activities. The consortium is currently scheduled to submit a license application for the facility to the Nuclear Regulatory Commission (NRC) in December 1996. The spent fuel storage facility is expected to be operational and able to accept the first shipment of used nuclear fuel by mid-2002. However, due to pending regulatory and governmental approval uncertainty, it is possible that this interim storage may be delayed or not available.

Fuel expense includes DOE fuel disposal assessments of $12.3 million, $10.6 million and $8.7 million for 1995, 1994 and 1993, respectively. Disposal expenses reflect reductions of $0.7 million in 1994 and $2.6 million in 1993 due to a change in the DOE's basis of charging customers, retroactive to 1983. Nuclear fuel expenses in 1995, 1994 and 1993 also include about $5 million, $5 million and $1 million, respectively, for payments to the DOE for the decommissioning and decontamination of the DOE's uranium enrichment facilities. The DOE's initial assessment of $46 million to the Company was recorded in 1993. This assessment will be payable in annual installments from 1993-2008 and each installment is being amortized to expense on a monthly basis in the 12 months following each payment. The most recent installment paid in 1995 was $3.7 million; future installments are subject to inflation adjustments under DOE rules. The Company is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, the unamortized assessment of $44 million at Dec. 31, 1995, has been deferred as a regulatory asset and is reported under the caption Environmental Costs in Note 10.

Plant Decommissioning Decommissioning of all Company nuclear facilities is planned for the years 2010-2022, using the prompt dismantlement method. The Company is currently following industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in Utility Plant – Accumulated Depreciation, as discussed in Note 1. Consequently, the total decommissioning cost obligation and corresponding asset currently are not recorded in NSP's financial statements. The FASB has proposed new accounting standards which, if approved as expected in 1996, would require the full accrual of nuclear plant decommissioning and certain other site exit obligations beginning in 1997. If NSP were to adopt the proposed accounting, beginning in 1997 an estimated total discounted decommissioning obligation of $610 million would be recorded as a liability, with the corresponding costs capitalized as a plant asset and depreciated over the operating life of the plant. The obligation calculation methodology proposed by the FASB is slightly different from the ratemaking methodology that derives the decommissioning accruals currently being recovered in rates (as discussed below). The Company has not yet determined the potential impact of the FASB's proposed changes in the accounting for site exit obligations other than nuclear decommissioning (such as costs of removal). However, the ultimate decommissioning and site exit costs to be accrued are the same under both methods and, accordingly, the

effects of regulation are expected to minimize or eliminate any impact on operating expenses and results of operations from this future accounting change.

Consistent with cost recovery in utility customer rates, the Company records annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Since the costs are expected to be paid in 2010-2022, funding presumes that current costs will escalate in the future at a rate of 4.5 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant recovery period. This annuity approach uses the assumed rate of return on funding, which is currently 6 percent (net of tax) for external funding and approximately 8 percent (net of tax) for internal funding.

The total obligation for decommissioning currently is expected to be funded approximately 82 percent by external funds and 18 percent by internal funds, as approved by the MPUC. Rate recovery of internal funding began in 1971 through depreciation rates for removal expense, and was changed to a sinking fund recovery in 1981. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. Costs not funded by external trust contributions and related earnings will be funded through internally generated funds and issuance of Company debt or stock. The assets held in trusts as of Dec. 31, 1995, primarily consisted of investments in tax-exempt municipal bonds, common stock of public companies and U.S. government securities.

The following table summarizes the funded status of the decommissioning obligation at Dec. 31, 1995, under the method currently in use.

(Millions of dollars)	1995
Decommissioning cost estimate from most recent study (1993 dollars)	$ 750.8
Effect of escalating costs to payment date (at 4.5% per year)	1 094.0
Estimated future decommissioning costs (undiscounted)	$1 844.8
Estimated decommissioning cost obligation escalated to current dollars	$ 819.9
External trust fund assets at fair value	203.6
Decommissioning obligation in excess of assets currently held in external trust	$ 616.3

Decommissioning expenses recognized include the following components:

(Millions of dollars)	1995	1994	1993
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$33.2	$33.2	$28.4
Internally funded (including interest costs)	1.2	1.1	14.5
Interest cost on externally funded decommissioning obligation	6.0	3.5	3.7
Earnings from external trust funds – net	(6.0)	(3.5)	(3.7)
Current year decommissioning accruals – net	$34.4	$34.3	$42.9

At Dec. 31, 1995, the Company has recorded and recovered in rates cumulative decommissioning accruals of $381 million; $177 million has been deposited into external trust funds for such accruals. The Company believes future decommissioning cost accruals will continue to be recovered in customer rates. Decommissioning and interest accruals are included with the accumulated provision for depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Income and Expense on the income statement.

A revision to NSP's 1993 nuclear decommissioning study and nuclear plant depreciation capital recovery request was filed with the MPUC and approved in 1994. Although management expects to operate the Prairie Island units through the end of their licensed lives, the approved capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs in 2008, about six years earlier than the end of its licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding used fuel storage. The updated nuclear decommissioning study resulted in a decrease in annual cost accruals for decommissioning due to a reduction in decommissioning cost estimates as well as the shortened recovery period. The combined impact of the request as approved, including the shorter depreciation period and lower decommissioning costs, was a net decrease of about $800,000 in annual depreciation and decommissioning expenses, beginning in 1994.

15. COMMITMENTS AND CONTINGENT LIABILITIES

Legislative Resource Commitments In 1994, the Minnesota Legislature established several energy resource and other commitments for NSP to fulfill to obtain the Prairie Island temporary nuclear fuel storage facility approval, as discussed in Note 14. The additional resource commitments, which can be built, purchased or (in the case of biomass generation) converted, can be summarized as follows:

Power Type	Megawatts		Deadline
Wind	100 (1)	(Additional)	12/31/96 (3)
Wind	225	(Cumulative)	12/31/98 (4)
Biomass	50	(Additional)	12/31/98 (5)
Wind	200	(Additional)	12/31/02
Biomass	75	(Additional)	12/31/02
Wind	400 (2)	(Additional)	12/31/02

(1) In addition to 25 megawatts of wind generation currently installed
(2) If required by least-cost planning and resource planning
(3) Power purchase contract awarded to Zond Systems, Inc.
(4) Power purchase bids to be received mid-1996
(5) Power purchase bid decision expected in March 1996

The Company has taken steps to comply with the requirements of these resource commitments. Twenty-five megawatts of third party wind generation has been fully operational since May 1, 1994. With respect to the additional 100 megawatts of wind energy to be under contract by the end of 1996, the Company has obtained a site designation from the Minnesota Environmental Quality Board (MEQB), and selected Zond Systems, Inc. to supply the wind energy. The Company must now secure wind rights for the site from an unsuccessful bidder, which has indicated it will not voluntarily transfer the wind rights. The

Company has commenced litigation to expedite resolution of the wind rights dispute. Siting and design activities are proceeding while wind rights acquisition efforts continue. An independent evaluator also reviewed proposals from bidders regarding 50 megawatts of farm-grown closed-loop biomass generation and made a recommendation to the Company in January 1996, with a final decision to be made in early 1996. On Jan. 22, 1996, the Company notified the MPUC that due to the price of the various bids and other factors, the Company intended to reject each of the bids. Since legislation may be proposed to change various elements of the biomass mandate, the Company proposed to delay its report detailing the Company's decision and its proposal to meet the statutory mandate until later in 1996.

Other commitments established by the Legislature include applying for, locating and licensing an alternative used fuel storage site, a low-income discount for electric customers, additional required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force formed in 1994. In January 1995, the MPUC approved the Company's low-income discount programs in accordance with the statute. In July 1995, the Company filed documents with the MEQB outlining two alternative Goodhue County sites to be considered for the development of an interim used nuclear fuel storage facility, as the Minnesota Legislature required. The MEQB has begun a 12- to 18-month public process to examine these sites and any others that may be proposed. The Company has implemented programs to begin meeting the other legislative commitments. The Company's capital commitments disclosed below include the known effects of the 1994 Prairie Island legislation. The impact of the legislation on power purchase commitments and other operating expenses is not yet determinable.

Capital Commitments NSP estimates utility capital expenditures, including acquisitions of nuclear fuel, will be $410 million in 1996 and $1.9 billion for 1996-2000. There also are contractual commitments for the disposal of used nuclear fuel. (See Note 14.)

NRG is contractually committed to additional equity investments in an existing German energy project. Such commitments are for approximately DM 33 million in 1996. The 1996 commitment would be approximately $23 million, based on exchange rates in effect at Dec. 31, 1995. In addition, NRG is contractually committed to additional equity investments of $17 million in the Scudder Latin American Trust for Independent Power Energy Projects, as of Dec. 31, 1995.

NRG is in the final stages of purchasing a 42 percent interest in O'Brien Environmental Energy, Inc. (O'Brien) from bankruptcy. In connection with its bid for O'Brien, on Jan. 3, 1996, NRG obtained a $100 million letter of credit from a bank, which is secured by a pledge of various NRG assets. NRG delivered the letter of credit to O'Brien on Jan. 18, 1996, to secure its obligation to complete its proposed investment in O'Brien. In January 1996, the United States Bankruptcy Court for the District of New Jersey confirmed the Chapter 11 Plan of Reorganization for O'Brien proposed by NRG and other interested parties. O'Brien has interests in eight domestic operating power generation facilities with aggregate capacity of approximately 230 megawatts, and in one 150-megawatt facility in the contract stage of development. As a result of the purchase, approximately $107 million would be made available to O'Brien's creditors by NRG. At least $81 million of the total made available to the creditors would be provided by NRG as follows: (i) a $28 million equity investment by NRG for its 42 percent interest in O'Brien; (ii) a $7.5 million investment by NRG for all of O'Brien's interest in certain biogas projects; and (iii) a $45 million unsecured loan from NRG to O'Brien. NRG currently is negotiating with an unaffiliated lender to refinance O'Brien's Newark Boxboard project in the amount of $56 million, of which approximately $26 million would be applied for distribution to O'Brien's creditors in reduction of NRG's approximately $107 million obligation. If this financing is not obtained concurrently with the closing of the O'Brien transaction, NRG would be obligated to make a $26 million loan to O'Brien after its reorganization.

Leases Rentals under operating leases were approximately $26.9 million, $24.0 million and $27.5 million for 1995, 1994 and 1993, respectively. Future commitments under these leases generally decline from current levels.

Fuel Contracts NSP has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts, which expire in various years between 1996 and 2013, require minimum contractual purchases and deliveries of fuel, and additional payments for the rights to purchase coal in the future. In total, NSP is committed to the minimum purchase of approximately $529 million of coal, $26 million of nuclear fuel and $512 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. In addition, NSP is required to pay additional amounts depending on actual quantities shipped under these agreements. As a result of FERC Order 636, NSP has been very active in developing a mix of gas supply, transportation and storage contracts designed to meet its needs for retail gas sales. The contracts are with several suppliers and for various periods of time. Because NSP has other sources of fuel available and suppliers are expected to continue to provide reliable fuel supplies, risk of loss from non-performance under these contracts is not considered significant. In addition, NSP's risk of loss (in the form of increased costs) from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of nearly all fuel costs.

Power Agreements The Company has executed several agreements with the Manitoba Hydro-Electric Board (MH) for hydroelectricity. A summary of the agreements is as follows:

	Years	Megawatts
Participation Power Purchase	1996-2005	500
Seasonal Participation Power Purchase	1996	250
Seasonal Peaking Power Purchase	1996	200
Seasonal Diversity Exchanges:		
Summer exchanges from MH	1996-2014	150
	1997-2016	200
Winter exchanges to MH	1996-2014	150
	1996-2015	200
	2015-2017	400
	2018	200

The cost of the 500-megawatt participation power purchase commitment is based on 80 percent of the costs of owning and operating the Company's Sherco 3 generating plant (adjusted to 1993 dollars). The total estimated future annual capacity costs for all MH agreements is projected to be approximately $65 million. However, the Company and MH have consented to arbitration to finalize interpretations of specific

contractual factors relating to the 500-megawatt participation agreement. These commitments to MH, which represent about 22 percent of MH's output capability in 1996, account for approximately 13 percent of NSP's 1996 electric system capability. The risk of loss from non-performance by MH is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

The Company has an agreement with Minnkota Power Cooperative (MPC) for the purchase of summer season capacity and energy. From 1996 through 2001, the Company will buy 150 megawatts of summer season capacity for $12.4 million annually. From 2002 through 2015, the Company will purchase 100 megawatts of capacity for $10.0 million annually. Under the agreement, energy will be priced against the cost of fuel consumed per megawatt-hour at the Coyote Generating Station in North Dakota. The Company also has three seasonal (summer) purchase power agreements with MPC, Minnesota Power and Mid American Energy Company for the purchase of 388 megawatts in 1996, including reserves. The annual cost of this capacity will be approximately $4 million.

The Company has agreements with several non-regulated power producers to purchase electric capacity and associated energy. The 1996 cost of these commitments for non-regulated installed capacity is approximately $20 million for 115 megawatts. This annual cost will increase to approximately $37 million-$44 million for 1997-2018 and then decrease to approximately $25 million-$29 million for 2019-2027 due to the expiration of existing agreements and an additional agreement for the purchase of 245 to 262 megawatts.

Nuclear Insurance The Company's public liability for claims resulting from any nuclear incident is limited to $8.9 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. The Company has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $8.7 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. The Company is subject to assessments of up to $79.3 million for each of its three licensed reactors to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

The Company purchases insurance for property damage and site decontamination cleanup costs with coverage limits of $2.0 billion for each of the Company's two nuclear plant sites. The coverage consists of $500 million from Nuclear Mutual Limited (NML) and $1.5 billion from Nuclear Electric Insurance Limited (NEIL).

NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums billed to NSP from NML and NEIL are expensed over the policy term. All companies insured with NML and NEIL are subject to retrospective premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NML and NEIL to the extent that the Company would have no exposure for retrospective premium assessments in case of a single incident under the business interruption and the property damage insurance coverages. However, in each calendar year, the Company could be subject to maximum assessments of approximately $4.9 million (five times the amount of its annual premium) and $36.8 million (generally 7.5 times the amount of its annual premium) if losses exceed accumulated reserve funds under the business interruption and property damage coverages, respectively.

Environmental Contingencies Other long-term liabilities include an accrual of $42 million, and other current liabilities include an accrual of $6 million at Dec. 31, 1995, for estimated costs associated with environmental remediation. Approximately $37 million of the long-term liability and $4 million of the current liability relate to a DOE assessment for decommissioning of a federal uranium enrichment facility, as discussed in Note 14. Other estimates have been recorded for expected environmental costs associated with manufactured gas plant sites formerly used by the Company and other waste disposal sites, as discussed below.

These environmental liabilities do not include accruals recorded (and collected from customers in rates) for future nuclear fuel disposal costs or decommissioning costs related to the Company's nuclear generating plants. (See Note 14 for further discussion.)

The Environmental Protection Agency (EPA) or state environmental agencies have designated the Company as a "potentially responsible party" (PRP) for 12 waste disposal sites to which the Company allegedly sent hazardous materials. Under applicable law, the Company, along with each PRP, could be held jointly and severally liable for the total remediation costs of all 12 sites, which are currently estimated between $123 million and $126 million. If additional remediation is necessary or unexpected costs are incurred, the amount could be in excess of $126 million. The Company is not aware of the other parties' inability to pay, nor does it know if responsibility for any of the sites is disputed by any party. The Company's share of the costs associated with these 12 sites is approximately $2.5 million. Of this amount, about $1.5 million already has been paid in connection with eight of the 12 sites for which the Company has settled with the EPA and other PRPs. For the remaining four sites, neither the amount of remediation costs nor the final method of their allocation among all designated PRPs has been determined. However, the Company has recorded an estimate of approximately $1 million for future costs for all four sites, with the estimated payment dates not determinable at this time. While it is not feasible to determine the outcome of these matters, amounts accrued represent the best current estimate of the Company's future liability for the remediation costs of these sites. It is the Company's practice to vigorously pursue and, if necessary, litigate with insurers to recover incurred remediation costs whenever possible. Through litigation, the Company has recovered from other PRPs a portion of the remediation costs paid to date. Management believes costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, should be allowed recovery in future ratemaking. Until the Company is identified as a PRP, it is not possible for the Company to predict the timing or amount of any costs associated with cleanup sites other than those discussed above.

The Wisconsin Company potentially may be involved in the cleanup and remediation at three sites. One site is a solid and hazardous waste landfill site in Eau Claire, Wis. The Wisconsin Company contends that it did not dispose of hazardous wastes in the subject landfill during the time period in question. Because neither the amount of cleanup costs nor the final method of their allocation among all designated PRPs has

been determined, it is not feasible to predict the outcome of this matter at this time. The second site, in Ashland, Wis., contains creosote/coal tar contamination. A portion of the Ashland site was contaminated by a gas manufacturing plant formerly operated by the Wisconsin Company. Cleanup at this portion of the site has begun and will be completed in 1996. The Wisconsin Company has paid approximately $400,000 and has accrued its estimated liability of $900,000 for the remainder of the cleanup. The Wisconsin Company is discussing its potential involvement in a second portion of the Ashland site with the Wisconsin Department of Natural Resources. Investigations are under way to determine the Wisconsin Company's responsibility as well as that of predecessor companies contributing to the contamination existing at the second portion of the Ashland site. The investigation also should determine the extent and source of the contamination and potential methods for remediation. An estimate of cleanup and remediation costs at the Eau Claire site and the second portion of the Ashland site and the extent of the Wisconsin Company's responsibility, if any, for sharing such costs are not known at this time. The third site is a landfill site in Hudson, Wis., which is one of the 12 waste disposal sites discussed previously.

The Company also is continuing to investigate 15 properties, either presently or previously owned by the Company, which were at one time sites of gas manufacturing, gas storage plants or gas pipelines. The purpose of this investigation is to determine if waste materials are present, if such materials constitute an environmental or health risk, if the Company has any responsibility for remedial action and if recovery under the Company's insurance policies can contribute to any remediation costs. Of the 15 gas sites under investigation, the Company already has remediated one site and is actively taking remedial action at four of the sites. In addition, the Company has been notified that two other sites eventually will require remediation, and a study will be initiated in 1996 to determine the cost and method of cleanup. Cleanup is expected to begin in 1997. The Company has paid $6.7 million to date on these seven active sites. The one remediated site continues to be monitored. The Company has recorded an estimated liability for future costs at the other six active sites of approximately $6.1 million, with payment expected over the next 10 years. This estimate is based on prior experience and includes investigation, remediation and litigation costs. As for the eight inactive sites, no liability has been recorded for remediation or investigation because the present land use at each of these sites does not warrant a response action. While it is not feasible to determine the precise outcome of all of these matters, the accruals recorded represent the current best estimate of the costs of any required cleanup or remedial actions at these former gas operating sites. Management also believes that incurred costs, which are not recovered from insurance carriers or other parties, should be allowed recovery in future ratemaking. During 1994, the Company's gas utility received approval for deferred accounting for certain gas remediation costs incurred at four active sites, with final rate treatment of such costs to be determined in future general gas rate cases.

The Clean Air Act, including the Amendments of 1990 (the Clean Air Act), calls for reductions in emissions of sulfur dioxide and nitrogen oxides from electric generating plants. These reductions, which will be phased in, began in 1995. The majority of the rules implementing this complex legislation have been finalized. No additional capital expenditures are anticipated to comply with the sulfur dioxide emission limits of the Clean Air Act. NSP has expended significant amounts over the years to reduce sulfur dioxide emissions at its plants. Based on revisions to the sulfur dioxide portion of the program, NSP's emission allowance allocations for the years 1995-1999 were dramatically reduced. The Company's capital expenditures include some costs for ensuring compliance with the Clean Air Act's other emission requirements; other expenditures may be necessary upon EPA's finalization of remaining rules. Because NSP is only beginning to implement some provisions of the Clean Air Act, its overall financial impact is unknown at this time. Capital expenditures for opacity compliance, which began in 1995 at certain facilities, are considered in the capital expenditure commitments disclosed previously. NSP plans to seek recovery of these expenditures in future rate proceedings.

Several of NSP's operating facilities have asbestos-containing material, which represents a potential health hazard to people who come in contact with it. Governmental regulations specify the required timing and nature of disposal of asbestos-containing materials. Under such requirements, asbestos not readily accessible to the environment need not be removed until the facilities containing the material are demolished. NSP estimates its future asbestos removal costs will approximate $43 million. Most of these costs will not need to be incurred until current operating facilities are demolished, and will be included in the costs of removal for the facilities.

Environmental liabilities are subject to considerable uncertainties that affect NSP's ability to estimate its share of the ultimate costs of remediation and pollution control efforts. Such uncertainties involve the nature and extent of site contamination, the extent of required cleanup efforts, varying costs of alternative cleanup methods and pollution control technologies, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties at multi-party sites and the identification of new environmental cleanup sites. NSP has recorded and/or disclosed its best estimate of expected future environmental costs and obligations, as discussed previously.

Legal Claims In the normal course of business, NSP is a party to routine claims and litigation arising from prior and current operations. NSP is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition. In July 1993, a natural gas explosion occurred on the Company's distribution system in St. Paul, Minn. Total damages are estimated to exceed $1 million. The Company has a self-insured retention deductible of $1 million, with general liability coverage of $150 million, which includes coverage for all injuries and damages. Seventeen lawsuits have been filed, including one suit with multiple plaintiffs. In April 1995, the National Transportation Safety Board found little, if any, fault with the Company's actions or conduct. A trial to decide civil liability and the parties responsible for the explosion has been scheduled for February 1997, with the damages portion of the trial scheduled for six months thereafter. The ultimate costs to the Company are unknown at this time.

16. SEGMENT INFORMATION

(Thousands of dollars)	Year Ended Dec. 31 1995	1994	1993
Utility operating income before income taxes			
Electric	$ 444 687	$ 399 185	$ 393 758
Gas	48 340	38 361	38 474
Total operating income before income taxes	$ 493 027	$ 437 546	$ 432 232
Utility depreciation and amortization			
Electric	266 231	$ 252 322	$ 245 200
Gas	23 953	21 479	19 317
Total depreciation and amortization	$ 290 184	$ 273 801	$ 264 517
Utility capital expenditures			
Electric utility	$ 317 750	$ 303 896	$ 284 229
Gas utility	37 215	60 183	36 312
Common utility	31 057	22 947	36 285
Total utility capital expenditures	$ 386 022	$ 387 026	$ 356 836
Identifiable assets			
Electric utility	$4 751 650	$4 634 511	$4 543 286
Gas utility	600 738	556 975	521 595
Total identifiable assets	$5 352 388	$5 191 486	$5 064 881
Other corporate assets*	876 197	758 246	522 837
Total assets	$6 228 585	$5 949 732	$5 587 718

** Includes equity investments of $185 million in 1995 and $134 million in 1994 in non-regulated energy projects outside of the United States.*

17. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

(Thousands of dollars)	Quarter Ended March 31, 1995	June 30, 1995	Sept. 30, 1995	Dec. 31, 1995
Utility operating revenues	$661 167	$589 673	$664 976	$652 768
Utility operating income	87 698	68 162	111 592	78 427
Net income	68 190	59 811	88 803	58 991
Earnings available for common stock	64 989	56 686	85 742	55 929
Earnings per average common share	$.97	$.84	$1.27	$.82
Dividends declared per common share	$.660	$.675	$.675	$.675
Stock prices – high	$46 ⅝	$47 ⅞	$46 ⅞	$49 ⅛
– low	$42 ⅛	$42 ⅞	$42 ⅛	$45 ⅛

(Thousands of dollars)	Quarter Ended March 31, 1994	June 30, 1994	Sept. 30, 1994	Dec. 31, 1994
Utility operating revenues	$683 462	$581 963	$612 328	$608 794
Utility operating income	85 795	65 526	88 932	68 065*
Net income	65 794	52 808	76 065	48 808*
Earnings available for common stock	62 737	49 751	72 968	45 655*
Earnings per average common share	$.94	$.74	$1.09	$.68*
Dividends declared per common share	$.645	$.660	$.660	$.660
Stock prices – high	$43 ⅞	$43 ⅝	$43 ⅛	$47
– low	$40 ⅛	$38 ¾	$40 ⅝	$41 ⅛

**An expense of $8.7 million ($5.1 million net of tax), or 8 cents per share, was recognized to write off the unamortized deferred costs associated with adopting SFAS No. 112. (See Note 2.) Such costs had initially been deferred based on a preliminary decision to request amortization through rates over future periods.*

18. MERGER AGREEMENT WITH WISCONSIN ENERGY CORPORATION

As previously reported in the Company's Current Report on Form 8-K, dated April 28, 1995, and filed on May 3, 1995, and Quarterly Reports on Form 10-Q, the Company and Wisconsin Energy Corporation (WEC) have entered into an Agreement and Plan of Merger (Merger Agreement), which provides for a strategic business combination involving the Company and WEC in a "merger-of-equals" transaction (the Transaction). See further discussion of the transaction in the Management's Discussion and Analysis, Factors Affecting Results of Operations – Proposed Merger section.

Primergy Corporation (Primergy), which will be registered under the Public Utility Holding Company Act of 1935, as amended, will be the parent company of both the Company (which, for regulatory reasons, will reincorporate in Wisconsin) and WEC's current principal utility subsidiary, Wisconsin Electric Power Company, which will be renamed "Wisconsin Energy Company." It is anticipated that, following the Transaction, except for certain gas distribution properties transferred to the Company, the Wisconsin Company will be merged into Wisconsin Energy Company and that some of the Company's other subsidiaries will become direct Primergy subsidiaries.

As noted above, pursuant to the Transaction, NSP will reincorporate in Wisconsin. This reincorporation will be accomplished by the merger of the Company into a new company, Northern Power Wisconsin Corporation (New NSP), with New NSP being the surviving corporation and succeeding to the business of the Company as an operating public utility. Following such merger, a new WEC subsidiary, WEC Sub Corporation (WEC Sub), will be merged with and into New NSP, with New NSP being the surviving corporation and becoming a subsidiary of Primergy. Both New NSP and WEC Sub were created to effect the Transaction and will not have any significant operations, assets or liabilities prior to such mergers. After the Transaction is completed, current common stockholders of the Company will own shares of Primergy common stock, and current bondholders and preferred stockholders of the Company will become investors in New NSP.

SUMMARIZED PRO FORMA FINANCIAL INFORMATION (UNAUDITED)

The following summary of unaudited pro forma financial information reflects the adjustment of the historical consolidated balance sheets and statements of income of NSP and WEC to give effect to the Transaction to form Primergy and a new subsidiary structure. The unaudited pro forma balance sheet information gives effect to the Transaction as if it had occurred on Dec. 31, 1995. The unaudited pro forma income statement information gives effect to the Transaction as if it had occurred on Jan. 1, 1995. This pro forma information was prepared from the historical consolidated financial statements of NSP and WEC on the basis of accounting for the Transaction as a pooling of interests and should be read in conjunction with such historical consolidated financial statements and related notes thereto of NSP and WEC. The following information is not necessarily indicative of the financial position or operating results that would have occurred had the Transaction been consummated on the dates for which the Transaction is being given effect, nor is it necessarily indicative of future Primergy operating results or financial position.

Primergy Information The following summarized Primergy pro forma financial information reflects the combination of the historical financial statements of NSP and WEC after giving effect to the Transaction to form Primergy. A $141 million pro forma adjustment has been made to conform the presentations of noncurrent deferred income taxes in the summarized pro forma combined balance sheet information as a net liability. The pro forma combined earnings per common share reflect pro forma adjustments to average common shares outstanding in accordance with the stock conversion provisions of the Merger Agreement.

Primergy Pro Forma Financial Information	NSP	WEC	Pro Forma Combined
(Millions of dollars, except per share amounts)			
As of Dec. 31, 1995:			
Utility Plant – Net	$4 310	$2 911	$ 7 221
Current Assets	705	531	1 236
Other Assets	1 214	1 119	2 192
Total Assets	$6 229	$4 561	$10 649
Common Stockholders' Equity	$2 028	$1 871	$ 3 899
Preferred Stockholders' Equity	240	30	270
Long-Term Debt	1 542	1 368	2 910
Total Capitalization	3 810	3 269	7 079
Current Liabilities	992	436	1 428
Other Liabilities	1 427	856	2 142
Total Equity and Liabilities	$6 229	$4 561	$10 649
For the Year Ended Dec. 31, 1995:			
Utility Operating Revenues	$2 569	$1 770	$4 339
Utility Operating Income	$346	$329	$675
Net Income, after Preferred Dividend Requirements	$263	$234	$497
Earnings per Common Share:			
As reported	$3.91	$2.13	
Using NSP Equivalent Shares*			$3.69
Using Primergy Shares			$2.27

** Represents the pro forma equivalent of one share of NSP Common Stock calculated by multiplying the pro forma information by the conversion ratio of 1.626 shares of Primergy Common Stock for each share of NSP Common Stock.*

New NSP Information The following summarized New NSP pro forma financial information reflects the adjustment of the historical financial statements of NSP to give effect to the Transaction, including the merger of the Wisconsin Company into Wisconsin Energy Company and the transfer of ownership of all of the other current NSP subsidiaries to Primergy. The transfer of certain Wisconsin Company gas distribution properties to New NSP, which is anticipated as part of the merger, has not been reflected in the pro forma amounts due to immateriality.

New NSP Pro Forma Financial Information	NSP	Merger Divestitures, Net	Pro Forma New NSP
(Millions of dollars)			
As of Dec. 31, 1995:			
Utility Plant – Net	$4 310	$ (692)	$3 618
Current Assets	705	(170)	535
Other Assets	1 214	(531)	683
Total Assets	$6 229	$(1 393)	$4 836
Common Stockholders' Equity	$2 028	$ (706)	$1 322
Preferred Stockholders' Equity	240		240
Long-Term Debt	1 542	(356)	1 186
Total Capitalization	3 810	(1 062)	2 748
Current Liabilities	992	(139)	853
Other Liabilities	1 427	(192)	1 235
Total Equity and Liabilities	$6 229	$(1 393)	$4 836
For the Year Ended Dec. 31, 1995:			
Utility Operating Revenues	$2 569	$(213)	$2 356
Utility Operating Income	$346	$(62)	$284
Net Income, after Preferred Dividend Requirements	$263	$(73)	$190

REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of NSP's financial statements. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include some amounts that are based on management's estimates and judgment.

To fulfill its responsibility, management maintains a strong internal control structure, supported by formal policies and procedures that are communicated throughout NSP. Management also maintains a staff of internal auditors who evaluate the adequacy of and investigate the adherence to these controls, policies and procedures.

Our independent public accountants have audited the financial statements and have rendered an opinion as to the statements' fairness of presentation, in all material respects, in conformity with generally accepted accounting principles. During the audit, they obtained an understanding of NSP's internal control structure, and performed tests and other procedures to the extent required by generally accepted auditing standards.

The Board of Directors pursues its oversight role with respect to NSP's financial statements through the Audit Committee, which is comprised solely of non-management directors. The Committee meets periodically with the independent public accountants, internal auditors and management to assure that all are properly discharging their responsibilities. The Committee approves the scope of the annual audit and reviews the recommendations the independent public accountants have for improving the internal control structure. The Board of Directors, on the recommendation of the Audit Committee, engages the independent public accountants, subject to shareholder approval.

Both the independent public accountants and the internal auditors have unrestricted access to the Audit Committee.

James J. Howard

James J. Howard
Chairman of the Board,
President and Chief Executive Officer

E J McIntyre

Edward J. McIntyre
Vice President and Chief
Financial Officer

NORTHERN STATES POWER COMPANY
Minneapolis, Minnesota
February 5, 1996

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Northern States Power Company: In our opinion, the accompanying consolidated balance sheet and statement of capitalization and the related consolidated statements of income, of common stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Northern States Power Company, a Minnesota corporation, and its subsidiaries at Dec. 31, 1995, and the results of their operations and their cash flows for the year in conformity with generally accepted accounting principles. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with generally accepted auditing standards which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for the opinion expressed above. The consolidated financial statements of the Company and its subsidiaries for the years ended Dec. 31, 1994 and 1993 were audited by other independent accountants whose report dated Feb. 8, 1995 expressed an unqualified opinion on those statements and included an explanatory paragraph related to a change in method of accounting for postretirement health care costs in 1993.

Price Waterhouse LLP

PRICE WATERHOUSE LLP
Minneapolis, Minnesota
February 5, 1996

Selected Financial Data

(Millions of dollars, except per share data)	1995	1994	1993	1992	1991	1985
Utility operating revenues	$2 568.5	$2 486.5	$2 404.0	$2 159.5	$2 201.1	$1 778.3
Utility operating expenses	$2 222.7	$2 178.2	$2 100.1	$1 903.5	$1 895.6	$1 531.6
Income from continuing operations before accounting change (4)	$275.8	$243.5	$211.7	$160.9	$207.0	$195.8
Net income	$275.8	$243.5	$211.7	$206.4	$224.1	$197.7
Earnings available for common stock	$263.3	$231.1	$197.2	$190.3	$206.1	$184.7
Average number of common and equivalent shares outstanding (000's)	67 416	66 845	65 211	62 641	62 566	62 274
Earnings per average common share:						
Continuing operations before accounting change (4)	$3.91	$3.46	$3.02	$2.31	$3.02	$2.94
Total	$3.91	$3.46	$3.02	$3.04	$3.29	$2.97
Dividends declared per share	$2.685	$2.625	$2.565	$2.495	$2.395	$1.725
Total assets	$6 228.6	$5 949.7	$5 587.7	$5 142.5	$4 918.8	$4 047.6
Long-term debt	$1 542.3	$1 463.4	$1 291.9	$1 299.9	$1 233.9	$1 252.5
Ratio of earnings (from continuing operations before accounting changes, including AFC) to fixed charges	3.9	4.0	4.0	3.2	3.9	4.7

Financial Statistics

	1995	1994	1993	1992	1991	1985
Return on average common equity:						
Continuing operations before accounting change (4)	13.4%	12.4%	11.4%	9.1%	12.2%	15.4%
Total earnings available for common stock	13.4%	12.4%	11.4%	11.9%	13.3%	15.6%
Dividends as percent of earnings (2)	68.5%	75.8%	85.5%	107.8%	72.7%	58.2%
Dividends as percent of book value	9.5%	9.7%	10.0%	10.0%	9.9%	9.6%
Five-year growth rate in earnings per share (1):						
Continuing operations before accounting change (4)	7.0%	1.0%	(2.9%)	(4.1%)	(0.6%)	13.4%
Total earnings available for common stock	5.2%	2.6%	0.1%	0.2%	0.5%	13.4%
Capital expenditures, excluding business acquisitions (millions)	$401.0	$409.3	$361.7	$427.8	$349.9	$513.7
Percent of capital expenditures that could be financed by internally generated funds (excluding AFC and after dividends)	85.0%	69.3%	98.5%	49.4%	57.7%	60.5%
Cash dividend coverage (2)	3.1	3.0	3.1	2.8	3.4	4.4
AFC as percent of earnings per share (2)	6.5%	5.4%	6.5%	10.5%	5.6%	22.6%
Effective tax rate	35.6%	34.7%	38.2%	34.9%	35.9%	44.5%
Capitalization (3)						
Common equity	48.4%	47.5%	49.4%	47.5%	49.6%	44.5%
Preferred equity	5.7%	6.0%	6.5%	8.0%	9.4%	7.9%
Debt	45.9%	46.5%	44.1%	44.5%	41.0%	47.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average cost of long-term debt	6.92%	7.34%	6.96%	7.87%	8.15%	8.08%
Average utility plant investment per dollar of revenue	$3.22	$3.19	$3.15	$3.32	$3.11	$2.71
Accumulated depreciation as a percent of depreciable plant	45.2%	43.3%	42.1%	40.4%	39.6%	33.9%
Depreciation expense as a percent of average depreciable utility plant	3.64%	3.55%	3.47%	3.36%	3.35%	3.63%
Benefit employees (at Dec. 31)	6 829	7 032	7 362	7 522	7 414	7 414

AFC – Allowance for Funds Used During Construction

(1) Least squares method

(2) Excludes the cumulative effect of unbilled revenue accounting change in 1992 earnings

(3) Includes short-term notes payable, current portion of long-term debt and preferred stocks with mandatory redemption

(4) Income and earnings from continuing operations exclude discontinued telephone operations (in 1991 and prior years) and an accounting change (in 1992). They include non-recurring items in 1994 and 1995, as discussed on page 25.

	1995	1994	1993	1992	1991	1985
Regulated Electric Operations						
Revenues *(thousands)*						
Residential						
With space heating	$ 67 332	$ 66 962	$ 68 222	$ 63 376	$ 67 878	$ 58 309
Without space heating	668 411	616 821	583 371	534 676	568 672	425 652
Small commercial and industrial	362 521	351 287	327 888	312 581	315 946	236 915
Medium commercial and industrial	399 259	*	*	*	*	*
Large commercial and industrial	448 228	824 195	780 444	718 712	713 177	515 794
Streetlighting and other	29 162	28 936	29 214	29 764	30 720	30 734
Total retail	1 974 911	1 888 201	1 789 139	1 659 109	1 696 393	1 267 404
Sales for resale	133 961	146 239	159 498	137 962	145 008	94 605
Miscellaneous	33 898	32 204	26 279	26 245	21 837	14 103
Total	$ 2 142 776	$ 2 066 644	$ 1 974 916	$ 1 823 316	$ 1 863 238	$ 1 376 112
Sales *(millions of kilowatt-hours)*						
Residential						
With space heating	1 111	1 076	1 094	1 041	1 141	1 066
Without space heating	8 845	8 227	7 998	7 640	8 226	6 900
Small commercial and industrial	5 763	5 585	5 307	5 224	5 330	4 326
Medium commercial and industrial	7 511	*	*	*	*	*
Large commercial and industrial	10 941	17 874	17 117	16 365	16 286	12 569
Streetlighting and other	329	334	344	372	386	500
Total retail	34 500	33 096	31 860	30 642	31 369	25 361
Sales for resale	6 500	6 733	8 044	6 530	6 083	4 211
Total	41 000	39 829	39 904	37 172	37 452	29 572
Customer accounts *(at Dec. 31)*						
Residential						
With space heating	76 344	76 050	75 644	74 939	74 646	66 668
Without space heating	1 162 232	1 146 578	1 131 928	1 119 354	1 104 772	1 010 194
Small commercial and industrial	144 774	142 858	141 446	140 768	139 266	125 992
Medium commercial and industrial	7 906	*	*	*	*	*
Large commercial and industrial	652	8 172	8 114	7 904	7 758	6 049
Streetlighting and other	4 883	4 836	4 813	4 627	7 662	5 245
Total retail	1 396 791	1 378 494	1 361 945	1 347 592	1 334 104	1 214 148
Sales for resale	67	70	71	74	72	81
Total	1 396 858	1 378 564	1 362 016	1 347 666	1 334 176	1 214 229
Residential with space heating						
Annual kwh per customer	14 571	14 224	14 531	13 950	15 272	16 522
Annual revenue per customer	$883.33	$885.19	$906.18	$849.08	$908.47	$903.72
Average revenue per kwh	6.06¢	6.22¢	6.24¢	6.09¢	5.95¢	5.47¢
Residential without space heating						
Annual kwh per customer	7 664	7 230	7 106	6 879	7 505	6 887
Annual revenue per customer	$579.15	$542.04	$518.34	$481.45	$518.83	$424.86
Average revenue per kwh	7.56¢	7.50¢	7.29¢	7.00¢	6.91¢	6.17¢
Kilowatt-hour output *(millions)*						
Thermal	33 802	32 710	33 130	30 467	31 335	24 095
Hydro	1 049	922	1 001	1 024	1 153	1 200
Purchased and interchange	9 189	9 054	8 541	8 187	7 019	6 317
Total	44 040	42 686	42 672	39 678	39 507	31 612
Capability at time of maximum demand *(megawatts)*						
Company owned	7 100	6 859	6 816	6 798	6 823	6 057
Purchased and sales – net (with reserve)	1 910	1 860	1 787	1 614	1 368	810
Total	9 010	8 719	8 603	8 412	8 191	6 867
Maximum demand *(megawatts)*	7 518	7 101	6 990	6 128	7 080	5 205
Date of maximum demand	July 13	June 14	Aug. 25	June 12	July 16	July 9

**Beginning in 1995, the commercial and industrial customer class has been segmented into small (less than 100 kw in demand per year), medium (100 kw up to 1,000 kw) and large (1,000 kw or more). The medium group, which is an estimate, was reported as large prior to 1995.*

	1995	1994	1993	1992	1991	1985
Regulated Gas Operations						
Revenues *(thousands)*						
Residential						
With space heating	$212 953	$204 668	$220 828	$178 164	$179 161	$195 248
Without space heating	2 690	2 838	2 715	2 523	2 614	3 838
Commercial and industrial						
Firm	113 863	120 912	131 431	105 829	105 703	118 760
Interruptible	48 640	49 384	52 216	41 612	40 768	81 501
Interstate transmission (Viking)*	13 954	14 075	9 019			
Miscellaneous**	27 008	28 026	12 867	8 078	9 674	2 853
Total	$425 814	$419 903	$429 076	$336 206	$337 920	$402 200
Sales *(thousands of mcf)*						
Residential						
With space heating	41 993	38 427	40 946	35 136	37 493	32 850
Without space heating	301	323	331	323	359	464
Commercial and industrial						
Firm	28 275	27 342	28 622	24 273	25 429	22 042
Interruptible	22 408	19 373	18 559	15 823	15 813	19 986
Miscellaneous	772	212	186	108	325	114
Total retail	93 749	85 677	88 644	75 663	79 419	75 456
Other gas delivered *(thousands of mcf)*						
Interstate transmission (Viking)*	132 512	131 074	75 188			
Agency, transportation and off-system sales	19 679	13 466	8 128	7 332	7 549	106
Total	152 191	144 540	83 316	7 332	7 549	106
Customer accounts *(at Dec. 31)*						
Residential						
With space heating	367 811	351 773	337 868	326 439	314 843	255 154
Without space heating	18 196	18 961	19 408	19 841	20 294	24 420
Commercial and industrial	38 575	37 140	36 185	35 458	34 663	28 414
Total	424 582	407 874	393 461	381 738	369 800	307 988
Residential with space heating						
Annual mcf per customer	117	112	124	110	122	131
Annual revenue per customer	$591.65	$595.30	$667.28	$557.83	$581.61	$779.75
Average revenue per mcf	$5.07	$5.33	$5.39	$5.07	$4.78	$5.94
Gas purchased for resale to utility customers						
Total cost *(thousands)****	$216 714	$245 939	$275 313	$216 743	$209 326	$300 375
Cost recognized per mcf sold***	$2.49	$2.85	$3.11	$2.86	$2.64	$3.98
Maximum sendout (mcf)	659 500	686 130	642 684	611 380	612 522	610 914
Date of maximum sendout	Jan. 3	Jan. 17	Dec. 27	Dec. 23	Feb. 14	Jan. 19

**Excludes intercompany sales revenues of $2.4 million (20,441 thousands of mcf) in 1995 and $2.2 million (16,845 thousands of mcf) in 1994*

***Includes NSP revenues for agency and transportation services and off-system sales*

****Excludes cost and volumes for other gas delivered*

(Thousands of dollars, except per share data)	1995	1994	1993
Operating Results			
Operating Revenues	$313 082	$241 827	$90 531
Operating Expenses (1)	(327 894)	(241 480)	(81 480)
Equity in earnings of unconsolidated affiliates:			
Earnings from operations (2)	28 095	31 595	2 695
Gains from contract terminations	29 858	9 685	
Other income (deductions) – net	6 518	1 843	1 040
Interest expense	(3 879)	(7 975)	(3 146)
Income taxes (2)	(6 119)	(2 591)	(3 548)
Net income	$33 613	$32 904	$6 092
Contribution of Non-regulated Businesses to NSP Earnings per Share			
NRG Energy, Inc.	$0.46	$0.44	$0.04
Eloigne Company	0.02	0.02	0.00
Cenergy, Inc. (Cenerprise, Inc., effective Jan. 1, 1996)	(0.02)	0.00	0.00
Other (3)	0.04	0.03	0.05
Total	$0.50	$0.49	$0.09

(Thousands of dollars)	1995	1994
Equity Investment by Non-regulated Businesses in Unconsolidated Projects at Dec. 31		
(Including undistributed earnings and capitalized development costs)		
Australian projects	$ 81 885	$75 108
German projects	87 699	55 337
Other international projects	14 920	4 013
Affordable housing projects (U.S.)	25 211	7 148
Other U.S. projects	54 276	36 152
Total Equity Investment in Unconsolidated Non-regulated Projects	$263 991	$177 758
Additional Equity Invested in Consolidated Non-regulated Businesses	115 276	104 011
Total Net Assets of Non-regulated Businesses	$379 267	$281 769

SIGNIFICANT UNCONSOLIDATED NON-REGULATED PROJECTS AT DEC. 31, 1995

Generation Projects Operating	Location	Total Mw	NRG Ownership	Mw-Equity	Operator
Gladstone Power Station	Australia	1680	37.5%	630	NRG
MIBRAG mbh	Germany	200	33.3%	67	Joint Venture-MIBRAG (NRG/Power-Gen plc/Morrison Knudsen Corp.)
San Joaquin Valley Energy Partners	California, USA	55	45.0%	25	Joint Venture-NRG/Volkar Coombs
Jackson Valley Energy Partners	California, USA	16	50.0%	8	Joint Venture-NRG/Volkar Coombs
Scudder Latin American Power Projects	Latin America	254	7.7%-10.3%	23	Stewart & Stevenson/Wartsila
Sunnyside Cogeneration Associates	Utah, USA	58	50.0%	29	Joint Venture-NRG/Babcock & Wilcox
Energy Center Kladno	Czech Republic	28	18.3%	5	Energy Center Kladno

Generation Projects Under Construction	Location	Total Mw	NRG Ownership	Mw-Equity	Operator
Schkopau Power Station	Germany	960	20.6%	200	Veba Kraftwerke Ruhr A.G.

Generation Projects Under Development (4)	Location	Total Mw	NRG Ownership	Mw-Equity	Operator
O'Brien Environmental Energy, Inc.	New Jersey, USA	203	42%	85	Stewart & Stevenson
Capitol District Energy Center Cogeneration Associates	Connecticut, USA	56	50%	28	Coastal
Collinsville	Australia	189	50%	95	NRG

(1) Includes project write-downs of $5.0 million in 1995 and $5.0 million in 1994.

(2) Equity in operating earnings is presented net of foreign income taxes of $6.3 million in 1995 and $3.8 million in 1994.

(3) Includes NSP-owned refuse-derived fuel operations managed by NRG.

(4) Projects under development may or may not be completed.

	1995	1994	1993	1992	1991	1985*
Common stock shareholders at year-end	83 962	85 263	86 404	72 525	72 704	82 234
Book value at year-end	$29.74	$28.35	$27.32	$25.91	$25.21	$19.72
Market prices						
High	$49 ⅜	$47	$47 ⅛	$45 ⅜	$44	$27 ⅜
Low	$42 ⅛	$38 ¾	$40 ⅛	$38 ½	$30	$20 ⅜
Year-end closing	$49 ⅜	$44	$43 ⅛	$43 ¼	$43	$26 ½
Dividends dec:ared per share	$2.685	$2.625	$2.565	$2.495	$2.395	$1.725
Earnings per share	$3.91	$3.46	$3.02	$3.04	$3.29	$2.97

**Adjusted for June 1986 two-for-one stock split.*

HEADQUARTERS:
414 Nicollet Mall, Minneapolis, MN 55401

STOCK INFORMATION:
Contact the Shareholders Department at NSP's headquarters. Call toll-free (800) 527-4677, Monday through Friday, 8 a.m. to 5 p.m. CST. From the Minneapolis-St. Paul area, call (612) 330-5560.

INVESTOR RELATIONS INFORMATION:
Contact Richard J. Kolkmann, Investor Relations, at NSP's headquarters. Call (612) 330-6622.

DIRECT DIVIDEND DEPOSIT:
NSP offers direct deposit of dividends to shareholders' checking or savings accounts. To sign up for this free service, contact the Shareholders Department for information and authorization forms.

SCHEDULE OF ANTICIPATED DIVIDEND RECORD DATES AND PAYMENT DATES FOR 1996:

Preferred Stock		Common Stock	
Record Dates	Payment Dates	Record Dates	Payment Dates
Dec. 29, 1995	Jan. 15, 1996	Jan. 2, 1996	Jan. 20, 1996
March 29, 1996	April 15, 1996	April 10, 1996	April 20, 1996
June 28, 1996	July 15, 1996	July 11, 1996	July 20, 1996
Sept. 30, 1996	Oct. 15, 1996	Oct. 1, 1996	Oct. 20, 1996
Dec. 31, 1996	Jan. 15, 1997		

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN:
The Company's Dividend Reinvestment and Stock Purchase Plan offered by Prospectus is a convenient way to purchase shares of the Company's common stock without payment of any brokerage commission or service charge. Those eligible to participate in the plan are:

- Shareholders of NSP
- Shareholders who hold stock in "street name" through investment firms, provided the firm has established procedures permitting participation
- Employees of NSP and its subsidiaries
- Non-shareholders of legal age who live in Minnesota, North Dakota, South Dakota, Wisconsin and Michigan (Non-shareholders must make an initial investment of at least $100)

Once enrolled in the plan, participants may:

- Automatically reinvest all or a portion of their quarterly dividends
- Make additional cash investments. The minimum single payment is $25 and the maximum quarterly payment is $10,000.

Contact the Shareholders Department for a Prospectus and authorization form.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL:
Common stock is traded on New York, Chicago, and Pacific Exchanges. NYSE lists some preferred stock. Ticker symbol: NSP. Newspaper stock tables list NSP as NoStPw, NoStPwr or NSPw. NSP's home page on the Internet is located at http://www.nspco.com

ANNUAL MEETING:
Wed., April 24, 1996, 10 a.m. at the Minneapolis Convention Center, Minneapolis, MN.

FORM 10-K (THE ANNUAL REPORT TO THE SECURITIES AND EXCHANGE COMMISSION):
Contact the Financial Accounting, Budgets and Reports Department at NSP headquarters. A statistical supplement to the annual report is also available. Call (612) 330-7772.

STREET-NAME SHAREHOLDERS AND BENEFICIAL OWNERS:
If you would like to receive NSP's quarterly report, contact the Financial Accounting, Budgets and Reports Department at NSP headquarters. Call (612) 330-7772.

DUPLICATE MAILINGS:
If there are two or more shareholders at your address, you may have received duplicate shareholder mailings. To eliminate duplicate mailings, write or call the Shareholders Department at NSP headquarters. Call toll-free (800) 527-4677, Monday through Friday, 8 a.m. to 5 p.m. CST. From the Minneapolis-St. Paul area, call 330-5560.

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Registrar, Common and Preferred Stocks
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St. Paul, MN 55101

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Milwaukee, WI 53202

Coupon-Paying Agents-Bonds
Firstar Trust Company
Milwaukee

First Bank, N.A.
201 West Wisconsin Ave.
Milwaukee, WI 53259

About the Covers

In addition to being home to NSP's corporate headquarters, the city of Minneapolis (front cover) provides a promising market for the company's Local Government Energy Conservation Program. As part of that effort, NSP offers local governments partial funding for engineering audits and design services, and provides no-interest financing to promote comprehensive energy retrofits.

Projects under way in Minneapolis include energy auditing and lighting retrofitting in as many as 65 city buildings. NSP also is working with the Minneapolis Water Works Department to test a new, energy-efficient method of treating water, and plans to finance \$2 million to \$3 million of improvements in 1996.

In St. Paul (back cover), where the program began in 1993, NSP has financed \$1.4 million of energy improvements, saving the city almost \$200,000 in annual energy costs. The city installed new equipment in 48 city buildings, and has audited and retrofitted more than 120 other electric services, such as pump stations.

The program continues to find new conservation opportunities. The St. Paul Public Works/Traffic Department has installed \$100,000 in new light-emitting diode (LED) traffic signal lighting, improving energy savings by up to 90 percent. The St. Paul Public Water Department will use the program to fund an estimated \$300,000 of their new dewatering process.

The Local Government Energy Conservation Program is part of NSP's ongoing effort to help customers conserve energy and manage its use. NSP's overall goal is to reduce system-wide peak electric demand by 1,700 megawatts by the year 2000. That not only enables customers to save energy and money, but allows NSP to postpone building large power plants. In 1995, the company and its customers achieved their greatest savings to date, reducing demand by 202 megawatts for a cumulative reduction of 1,224 megawatts.

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