

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended Dec. 31, 2000 Commission File Number 1-3034

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934



Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

Minnesota

(State of other jurisdiction of incorporation of organization)

41-0448030

(I.R.S. Employer Identification No)

800 Nicollet Mall, Minneapolis, Minnesota

(Address of principal executive offices)

55402

(Zip Code)

Registrant's telephone number, including area code **(612) 330-5500**

Northern States Power Company

414 Nicollet Mall, Minneapolis, Minnesota 55401

Former name, former address and former fiscal year, if changed since last report

Securities registered pursuant to Section 12(b) of the Act:

<u>Registrant</u>	<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
Xcel Energy Inc.	Common Stock, \$2.50 par value per share	New York, Chicago, Pacific
Xcel Energy Inc.	Cumulative Preferred Stock, \$100 Par Value	New York
Xcel Energy Inc.	Preferred Stock \$3.60 Cumulative	New York
Xcel Energy Inc.	Preferred Stock \$4.08 Cumulative	New York
Xcel Energy Inc.	Preferred Stock \$4.10 Cumulative	New York
Xcel Energy Inc.	Preferred Stock \$4.11 Cumulative	New York
Xcel Energy Inc.	Preferred Stock \$4.16 Cumulative	New York
Xcel Energy Inc.	Preferred Stock \$4.56 Cumulative	New York

Securities registered pursuant to Section 12(g) of Act: None

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

As of March 15, 2001, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was \$9,605,563,141 and there were 342,441,953 shares of common stock outstanding, \$2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its Annual Meeting of Shareholders, to be held April 25, 2001, are incorporated by reference into Part III of this Form 10-K.

Index

	<u>Page No.</u>
PART I	
Item 1—Business	3
COMPANY OVERVIEW	
UTILITY REGULATION	
Ratemaking Principles	5
Fuel, Purchased Gas and Resource Adjustment Clauses	6
Regulatory Matters	8
ELECTRIC UTILITY OPERATIONS	
Competition and Industry Restructuring	10
Capacity and Demand	13
Energy Sources	13
Fuel Supply and Costs	15
Nuclear Power—Operations and Waste Disposal	17
Electric Operating Statistics	19
GAS UTILITY OPERATIONS	
Competition and Industry Restructuring	19
Capability and Demand	20
Gas Supply and Costs	21
Gas Operating Statistics	23
NONREGULATED SUBSIDIARIES	
NRG Energy, Inc.	24
Yorkshire Power.	27
Utility Engineering.	27
e prime.	28
Planergy International.	28
Seren Innovations, Inc.	28
Eloigne Company	28
IPC/IPI	28
ENVIRONMENTAL MATTERS	29
CAPITAL SPENDING AND FINANCING	29
EMPLOYEES	29
EXECUTIVE OFFICERS	29
Item 2—Properties	30
Item 3—Legal Proceedings	34
Item 4—Submission of Matters to a Vote of Security Holders	34
PART II	
Item 5—Market for Registrant’s Common Equity and Related Stockholder Matters	35
Item 6—Selected Financial Data	36
Item 7—Management’s Discussion and Analysis	37
Item 7A—Quantitative and Qualitative Disclosures about Market Risk	54
Item 8—Financial Statements and Supplementary Data	54
Item 9—Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	101
PART III	
Item 10—Directors and Executive Officers of the Registrant	101
Item 11—Executive Compensation	101
Item 12—Security Ownership of Certain Beneficial Owners and Management	101
Item 13—Certain Relationships and Related Transactions	101
PART IV	
Item 14—Exhibits, Financial Statement Schedules, and Reports on Form 8-K	102
SIGNATURES	116
EXHIBIT (EXCERPT)	
Ratio of Earnings to Fixed Charges	
Statement Pursuant to Private Securities Litigation Reform Act	

ITEM 1—BUSINESS

COMPANY OVERVIEW

On Aug. 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act (PUHCA). Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares), and accounted for as a pooling-of-interests. As part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of Xcel Energy named Northern States Power Company.

Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are Northern States Power Company, a Minnesota corporation (NSP-Minnesota), Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), Public Service Company of Colorado (PSCo), Southwestern Public Service Company (SPS), Black Mountain Gas Company (BMG) and Cheyenne Light, Fuel and Power Company (Cheyenne). Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy's regulated businesses also include Viking Gas Transmission Company and WestGas InterState Inc. (WGI), both interstate natural gas pipeline companies.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., a publicly traded independent power producer. At Dec. 31, 2000, Xcel Energy indirectly owned 82 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering. During March 2001, NRG issued an additional 18.4 million shares of common stock, which caused Xcel Energy's ownership interest in NRG to decline to approximately 75 percent. For more information, see NRG Initial Public Offering discussed under Liquidity and Capital Resources in Management's Discussion and Analysis under Item 7.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Seren Innovations, Inc. (broadband telecommunications services), e prime, inc. (natural gas marketing and trading), Planergy International Inc. (energy management, consulting and demand-side management services) and Eloigne Company (acquisition of rental housing projects that qualify for low-income housing tax credits). Xcel Energy also reports in its nonregulated activities its 50-percent stake in Yorkshire Power, a regional electricity company in the United Kingdom. Subsequent to year-end, Xcel Energy has agreed to sell a substantial portion of this investment. For more information, see Note 11 to the Financial Statements under Item 8.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group, Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc., Xcel Energy O&M Services Inc. and Xcel Energy Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy was incorporated under the laws of Minnesota in 1909. Its executive offices are located at 800 Nicollet Mall, Minneapolis, Minnesota 55401.

For information on the nonregulated subsidiaries of Xcel Energy, see Nonregulated Subsidiaries under Item 1. For information regarding Xcel Energy's segments and foreign revenues, see Note 18 to the Financial Statements under Item 8.

NSP-Minnesota

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. NSP-Minnesota provides generation, transmission and distribution of electricity in Minnesota, North Dakota and South Dakota. NSP-Minnesota also purchases, distributes and sells natural gas to retail customers and transports customer-owned gas in Minnesota, North Dakota and South Dakota. NSP-Minnesota provides retail electric utility service to approximately 1.3 million customers and gas utility service to approximately 0.4 million customers.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; First Midwest Auto Park Inc., which owns and operates a parking ramp; NSP Nuclear Corp., which holds NSP-Minnesota's interest in the Nuclear Management Company; and NSP Financing I, a special purpose business trust.

NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 225,000 retail customers in northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin is also engaged in the distribution and sale of natural gas in the same service territory to approximately 90,000 customers in Wisconsin and Michigan.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Company, which operates hydro reserves; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is an operating utility engaged principally in the generation, purchase, transmission, distribution and sale of electricity and the purchase, transportation, distribution and sale of natural gas. PSCo serves approximately 1.2 million electric customers and approximately 1.1 million gas customers in Colorado.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc., which owns certain real estate interests of PSCo; P.S.R. Investments, Inc., which owns and manages permanent life insurance policies on certain employees; PS Colorado Credit Corporation, a finance company that finances certain of PSCo's current assets; and Green and Clear Lakes Company, which owns water rights. PSCo also holds a controlling interest in several other relatively small ditch and water companies whose capital requirements are not significant.

SPS

SPS was incorporated in 1921 under the laws of New Mexico. SPS is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas. The wholesale customers served by SPS comprise approximately 34 percent of the total kilowatt-hour sales.

Other Regulated Subsidiaries

Cheyenne was incorporated in 1900 under the laws of Wyoming. Cheyenne is an operating utility engaged in the purchase, transmission, distribution and sale of electricity and natural gas primarily serving approximately 36,000 electric customers and 29,000 natural gas customers in and around Cheyenne, Wyo.

BMG was incorporated in 1999 under the laws of Minnesota. BMG is a natural gas and propane distribution company, located in Cave Creek, Ariz., with approximately 6,500 customers.

Viking Gas, acquired in 1993, owns and operates an interstate natural gas pipeline serving portions of Minnesota, Wisconsin and North Dakota. Viking operates exclusively as a transporter of natural gas for third-party shippers under authority granted by the Federal Energy Regulatory Commission (FERC).

WGI was incorporated in 1990 under the laws of Colorado. WGI is a natural gas transmission company engaged in transporting gas from Chalk Bluffs, Colo., to Cheyenne, Wyo.

UTILITY REGULATION

Ratemaking Principles

The Xcel Energy system is subject to the jurisdiction of the Securities and Exchange Commission (SEC) under PUHCA. The rules and regulations under PUHCA generally limit the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce, hydro facility licensing, the wholesale gas transportation rates of Viking, the siting and construction of facilities by Viking and certain other activities of Xcel Energy's utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of Xcel Energy's other activities.

Xcel Energy is unable to predict the impact on its operating results from the future regulatory activities of any of these agencies. Xcel Energy strives to comply with all rules and regulations issued by the various agencies.

NSP-Minnesota

Retail rates, services and other aspects of NSP-Minnesota's operations are subject to the jurisdiction of the Minnesota Public Utilities Commission (MPUC), the North Dakota Public Service Commission (NDPSC) and the South Dakota Public Utilities Commission (SDPUC) within their respective states. The MPUC also possesses regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans and gas supply plans for meeting customers' future energy needs.

The Minnesota Environmental Quality Board (MEQB) is empowered to select and designate sites for new power plants with a capacity of 50 megawatts or more and wind energy conversion plants with a capacity of five megawatts or more. It also designates routes for electric transmission lines with a capacity of 200 kilovolts (kv) or more. No power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MEQB.

NSP-Wisconsin

NSP-Wisconsin is subject to regulation of similar scope by the Public Service Commission of Wisconsin (PSCW) and the Michigan Public Service Commission (MPSC). In addition, each of the state commissions certifies the need for new generating plants and electric and retail gas transmission lines of designated capacities to be located within the respective states before the facilities may be sited and built.

The PSCW has a biennial filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit rate filings for calendar years beginning the following January. The filing procedure and

review generally allow the PSCW sufficient time to issue an order effective with the start of the test year.

PSCo

PSCo is subject to the jurisdiction of the Colorado Public Utility Commission (CPUC) with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is subject to the jurisdiction of the FERC with respect to its wholesale electric operations and accounting practices and policies. PSCo has received authorization from the FERC to act as a power marketer. Also, PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.

SPS

The Public Utility Commission of Texas (PUCT) has jurisdiction over SPS' Texas operations as an electric utility and original and appellate jurisdiction over its retail rates and services. The New Mexico Public Regulatory Commission (NMPRC) has jurisdiction over the issuance of securities and accounting. The NMPRC, the Oklahoma Corporation Commission and the Kansas Corporation Commission have jurisdiction with respect to retail rates and services in their respective states. The FERC has jurisdiction over SPS' rates for sales for resale and the transmission of electricity in interstate commerce.

Cheyenne

Cheyenne is subject to the jurisdiction of the Wyoming Public Service Commission (WPSC) with respect to its facilities, rates, accounts, services and issuance of securities. All electric demand and purchased power costs are recoverable through an energy adjustment clause. Differences in costs incurred from costs recovered in rates are deferred and recovered through prospective adjustments to rates. However, rate changes for cost recovery require WPSC approval before going into effect. Historically, customers have been provided carrying costs on overcollected costs, but Cheyenne has not been allowed to collect carrying charges for under recovered costs.

Other

Viking and WGI are subject to FERC jurisdiction and each holds a FERC certificate, which allows them to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act.. BMG is subject to the Arizona Corporation Commission (ACC).

Fuel, Purchased Gas and Resource Adjustment Clauses

NSP-Minnesota

NSP-Minnesota's retail electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy. NSP-Minnesota is permitted to recover option costs through a fuel clause adjustment, a mechanism that allows NSP-Minnesota to bill customers for the actual cost of fuel used to generate electricity at its plants and energy purchased from other suppliers. Changes in capacity charges are not recovered through the fuel clause. NSP-Minnesota's electric wholesale customers do not have a fuel clause provision in their contracts. Instead, the contracts have an escalation factor.

Gas rate schedules for NSP-Minnesota include a purchased gas adjustment (PGA) clause that provides for rate adjustments for changes in the current unit cost of purchased gas compared with the last costs included in rates. The PGA factors in Minnesota are calculated for the current month based on the estimated purchased gas costs for that month.

By September of each year, NSP-Minnesota is required to submit to the MPUC an annual report of the PGA factors used to bill each customer class by month for the previous year commencing July 1

and ending June 30. The report verifies whether the utility is calculating the adjustments properly and implementing them in a timely manner. In addition, the MPUC reviews procurement policies, cost-minimizing efforts, rule variances, retail transportation gas volumes, independent auditors' reports and the impact of market forces on gas costs for the coming year. The MPUC has the authority to disallow certain costs if it finds the utility was not prudent in its gas procurement activities.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue and 0.5 percent of Minnesota gas revenue on conservation improvement programs (CIP). These costs are recovered through an annual recovery mechanism for electric and gas conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually.

NSP-Wisconsin

NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference outside a prescribed range, the PSCW may hold hearings limited to fuel costs and revise rates. Any revised rates would be effective until the next rate case. The adjustment approved is calculated on an annual basis, but applied prospectively. Most of NSP-Wisconsin's wholesale electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

During 1999, the PSCW approved a new gas cost recovery mechanism to replace the PGA. The financial impact of the gas cost recovery mechanism is substantially the same as with the former PGA.

NSP-Wisconsin's gas and retail electric rate schedules for Michigan customers include gas cost recovery factors and power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers.

PSCo

PSCo has five adjustment clauses: the incentive cost adjustment (ICA), the gas cost adjustment (GCA), the steam cost adjustment (SCA), the demand side management cost adjustment (DSMCA) and the qualifying facilities capacity cost adjustment (QFCCA). These adjustment clauses allow certain costs to be passed through to retail customers. PSCo is required to file applications with the CPUC for approval of adjustment mechanisms in advance of the proposed effective dates. The applications must be acted upon before becoming effective.

The ICA allows for an equal sharing between customers and shareholders of certain fuel and energy cost increases. PSCo, through its GCA, is allowed to recover its actual costs of purchased gas. The GCA rate is revised annually in October, and otherwise as needed, to coincide with changes in purchased gas costs. Purchased gas costs and revenues received to recover such gas costs are compared on a monthly basis and differences are deferred. PSCo, through its SCA, is allowed to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base rates. The SCA rate is revised annually in January, and otherwise as needed, to coincide with changes in fuel costs. The QFCCA provides for recovery of purchased capacity costs from certain QF projects not otherwise reflected in base electric rates.

The DSMCA clause currently permits PSCo to recover DSM costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. PSCo also has implemented a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the DSMCA.

SPS

Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS' rates. If it appears that SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the PUCT. The rule requires refunding and surcharging under/over-recovery amounts, including interest, when they exceed 4 percent of the utility's annual fuel and purchased power costs, as allowed by the PUCT, if this condition is expected to continue. PUCT regulations require periodic examination of SPS fuel and purchased power costs, the efficiency of the use of such fuel and purchased power, fuel acquisition and management policies and purchase power commitments. Under the PUCT's regulations, SPS is required to file an application for the PUCT to retrospectively review at least every three years the operations of SPS' electric generation and fuel management activities.

The NMPRC regulations provide for a fuel and purchased power cost adjustment clause and a fixed annual fuel factor for SPS' New Mexico retail jurisdiction. SPS files monthly and annual reports of its fuel and purchased power costs with the NMPRC, which include the current over/under fuel collection calculation, plus interest. In addition, SPS revises its fixed fuel factor annually to recover projected fuel and purchased power costs as well as any over/under cost balance for the current year. SPS is required to petition for a change in the fixed fuel factor if the over/under recovery balance reaches \$5 million.

Regulatory Matters

NSP-Minnesota

Conservation Recovery—NSP-Minnesota had a 4.1 percent conservation rate surcharge in place since 1998, pending resolution of the conservation incentive recovery issue. On July 31, 2000, the MPUC approved NSP-Minnesota's request to prospectively reduce the surcharge level to 0.68 percent (consistent with current costs to be recovered) and to refund cumulative overcollections of approximately \$24 million. The refund occurred during December 2000. Although cash flows were reduced, NSP-Minnesota did not have any earnings impact from these actions due to accruals previously recorded. For more information, see Management's Discussion and Analysis under Item 7.

Fuel Clause Adjustment—In June 2000, the MPUC approved a change under which bills received by NSP-Minnesota's electricity customers will more accurately reflect energy costs on a timely basis. Previously, the adjustment reflected prior period costs, and it would take approximately three months for customer bills to reflect higher, or lower, fuel costs incurred by NSP-Minnesota. Under the new method, NSP-Minnesota bases the customer billing adjustment on projected energy costs for the current month, and corrects, in a subsequent month, any differences between projected costs and actual costs incurred. This improved matching between costs and usage should encourage customers to take appropriate steps to reduce energy use during peak periods—when costs are at their highest—while giving appropriate price signals when costs are lower during off-peak periods. NSP-Minnesota implemented the revised fuel clause adjustment with July 2000 billings.

Energy Cost Recovery—In April 2000, the Minnesota Office of Attorney General (OAG) filed a petition with the MPUC asking the MPUC to initiate an investigation of NSP-Minnesota's fuel and purchased energy cost recoveries under the FCA provisions of NSP's tariffs. The OAG alleged NSP-Minnesota could be improperly diverting low-cost NSP-Minnesota generation supplies to the wholesale market to increase profits, while recovering higher-cost energy purchases through the FCA. NSP-Minnesota contends that it has followed the appropriate FCA rules and regulations. In July 2000, the MPUC issued an order in which it indicated that the record before the MPUC did not reflect any specific allegations of wrongdoing. However, the MPUC instructed NSP-Minnesota and the OAG to resolve any concerns and file a report with the MPUC. The report is pending.

North Dakota Rate Case—In October 2000, NSP-Minnesota filed a request with the NDPSC to increase natural gas rates by approximately 3.3 percent, or \$1.4 million, annually. Evidentiary hearings are scheduled for April 2001 with an order likely during the second quarter of 2001.

NSP-Wisconsin

Temporary Fuel Cost Surcharge—In May 2000, the PSCW issued an order granting a fuel surcharge to increase electric rates to recover higher fuel costs. The increase was primarily the result of higher purchased power costs than were anticipated in base rates. The surcharge factor increased revenues by approximately \$6.4 million in 2000 and represented an average increase for all customer classes of approximately 2 percent. The surcharge factor is expected to be effective through Dec. 31, 2001.

PSCo

Gas Rate Case—In July 2000, PSCo filed a retail rate case with the CPUC requesting an annual increase in its gas revenues of approximately \$40 million. The request for a rate increase reflects revenues for additional plant investment, a 12.5-percent return on equity, new depreciation rates and recovery of the dismantlement costs associated with the Leyden Gas Storage facility. In February 2001, the CPUC granted an increase in gas revenues of \$14.2 million and authorized an 11.25-percent return on equity. The CPUC did not grant the new depreciation rates proposed by PSCo, but rather granted new depreciation rates proposed by the CPUC staff. The CPUC denied recovery of the dismantlement costs associated with the Leyden Gas Storage facility in this case and recommended PSCo request recovery in a later case.

SPS

Fuel Recovery—At least every three years, SPS is required to file an application for the PUCT to retrospectively review the operations of a utility's electricity generation and fuel management activities. In June 2000, SPS filed an application for the PUCT to retrospectively review the operations of the utility's electricity generation and fuel management activities. In this application, SPS filed its reconciliation for generation and fuel management activities totaling approximately \$419 million, for the period from January 1998 through December 1999. SPS expects to be granted recovery of these costs. Final approval is pending.

SPS filed an application in July 2000 seeking to increase its fixed fuel factors as a result of recent increases in natural gas costs. In August 2000, SPS filed a second application seeking authority to surcharge approximately \$26 million in fuel under-recoveries and related interest accrued through the June 2000 billing cycle over the eight months ending May 2001. In August 2000, the PUCT consolidated these two filings into one docket. SPS reached a unanimous stipulation with all parties to the case resolving all outstanding issues. This stipulation was approved by the PUCT in September 2000, which allowed the new fuel factors and surcharge factors to become effective in the October 2000 billing cycle.

In October 2000, SPS filed an unopposed motion with the NMPRC, seeking to change the date for the implementation of its next fixed annual fuel factor. SPS was approximately \$12.8 million under-collected in fuel and purchased power costs through August 2000 and projected that these under-collections would continue based on recent increases in natural gas costs. In October 2000, the NMPRC approved SPS' revised fixed annual fuel factor to be effective in the November 2000 billing cycle.

In November 2000, SPS filed an application with the PUCT seeking authority to surcharge approximately \$43 million in fuel under recoveries and related interest accrued during July 2000 through September 2000. SPS reached a unanimous stipulation with all parties to the case resolving all outstanding issues. In January 2001, the PUCT approved the surcharge and required amounts be applied to customers bills over an eleven-month period starting February 2001.

Cheyenne

On March 15, 2001, Cheyenne filed an application with the WPSC requesting approval to pass through to electric customers an increase in the cost of electricity and transmission of \$36 million for the remainder of 2001. The increase is requested to be effective April 15, 2001. The application follows a dramatic increase in Cheyenne's contractual electric purchase costs. Normally, the full cost of these increases are passed through to customers on a dollar-for-dollar basis. However, as part of its application, Cheyenne has requested approval to defer recovery of approximately \$61 million of increased power costs for a period of five years. The WPSC has opened an investigation into the proposed rate increase with hearings scheduled to begin April 2001. For more information on the increase in Cheyenne's purchase power costs, see Management's Discussion and Analysis under Item 7.

For more information on regulatory matters, see Management's Discussion and Analysis under Item 7.

ELECTRIC UTILITY OPERATIONS

Competition and Industry Restructuring

Retail competition and the unbundling of regulated energy service could have a significant financial impact on Xcel Energy and its subsidiaries, due to an impairment of assets, a loss of retail customers, lower profit margins and increased costs of capital. The total impacts of restructuring may have a significant financial impact on the financial position, results of operations and cash flows of Xcel Energy. Xcel Energy and its utility subsidiaries cannot predict when they will be subject to changes in legislation or regulation, nor can they predict the impacts of such changes on their financial position, results of operations or cash flows. Xcel Energy believes that the prices its utility subsidiaries charge for electricity and the quality and reliability of their service currently place them in a position to compete effectively in the energy market.

Retail Business Competition—The retail electric business faces increasing competition as industrial and large commercial customers have some ability to own or operate facilities to generate their own electric energy. In addition, customers may have the option of substituting other fuels, such as natural gas for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost environment. While each of Xcel Energy's utility subsidiaries face these challenges, these subsidiaries believe their rates are competitive with currently available alternatives. Xcel Energy's utility subsidiaries are taking actions to lower operating costs and are working with their customers to analyze energy efficiency, load management and cogeneration in order to better position Xcel Energy's utility subsidiaries to more effectively operate in a competitive environment.

Wholesale Business Competition—The wholesale electric business faces increasing competition in the supply of bulk power, due to federal and state initiatives to provide open access to utility transmission systems. Under current FERC rules, utilities are required to provide wholesale open-access transmission services and to unbundle wholesale merchant and transmission operations. Xcel Energy's utility subsidiaries are operating under a joint tariff in compliance with these rules. To date, these provisions have not had a material impact on the operations of Xcel Energy's utility subsidiaries.

NSP-Minnesota

Minnesota Restructuring—During the summer of 2000, the Commerce Commissioner, Attorney General, Senate Majority Leader and House Speaker all publicly identified the potential shortage in electric supply as a critical issue for the coming legislative session. Each of these leaders expressed hesitation about adopting a comprehensive restructuring proposal, but they acknowledged the need for reforms in our power supply regulatory system. The Minnesota Chamber of Commerce still intends to push for a comprehensive restructuring bill. Based on the recommendations made by the Department of Commerce in their report "Keeping the Lights On," it is likely that reform of utility taxation and generation and transmission siting will be two of the issues debated by the 2001 Legislature.

North Dakota Restructuring—In 1997, the North Dakota Legislature established an Electric Utility Committee charged with studying the impact of competition on the electric industry. The committee has six years to study the impact of competition on the electric energy industry in the state. During 2000, the committee began the study of the current tax structure on the industry. The committee was also given the responsibility for assessing the need for modifications to the Territorial Integrity Act, a law governing distribution service territories within the state. The final report presented to the legislative council made no recommendations to change the current tax structure at the present time. The committee will resume its work after the 2001 legislative session.

In December 2000, the NDPSC approved Xcel Energy's "PLUS" Performance Based Regulation proposal, effective January 2001 for its electric operations in the state. The plan establishes performance standards for reliability, customer service, price and employee safety. The company's performance determines its allowed return on equity. The plan also includes revenue sharing and a price cap mechanism. The plan will remain in effect through 2005.

NSP-Wisconsin

Wisconsin Restructuring—During 1999, Wisconsin state lawmakers passed "Reliability 2000" legislation, which included steps necessary to further progress toward a restructured industry, eventually including allowing retail customers to choose their electric supplier. One of the provisions of the legislation establishes a public benefits fund, to be administered by the State of Wisconsin, which will use money collected from Wisconsin utilities' customers to pay for low-income assistance, conservation programs and renewable energy and environmental research programs. NSP-Wisconsin began collecting the public benefits surcharge from its Wisconsin customers in October 2000.

In April 1998, Wisconsin state legislators enacted a law that includes provisions that require the PSCW to order a public utility that owns transmission facilities in Wisconsin to transfer control of its transmission facilities to an independent system operator (ISO) or divest its interest in its transmission facilities to an independent transmission company (ITC) by June 2000. NSP-Minnesota and NSP-Wisconsin joined the Midwest ISO (MISO) in 1999 and filed for PSCW and FERC approval in March 2000. The MISO is not expected to be operational until November 2001. In June 2000, the PSCW issued an order that effectively waived the deadline for the state's five major utilities, including NSP-Wisconsin, to relinquish transmission system control. In October 2000, the PSCW issued an order authorizing NSP-Wisconsin's transfer of operating control of its transmission system to the MISO.

Michigan Restructuring—In June 2000, Michigan's "Customer Choice and Electricity Reliability Act," became law. The passage of the Act means there will be customer choice for all customers in Michigan, including NSP-Wisconsin's customers in the Upper Peninsula, starting January 2002. Key elements of the law include developing distribution reliability and performance standards and environmental and fuel disclosure standards, codes of conduct, customer and employee education programs and an Upper Peninsula Market Power Study. The Act also contains a number of consumer protection provisions dealing with cramming, slamming and low-income energy assistance. NSP-Wisconsin filed its preliminary restructuring plan in October 2000 and revisions to the preliminary restructuring plan in February 2001. NSP-Wisconsin expects to file its unbundled rates by June 2001. The five-percent rate reduction and rate freeze ordered in the Act does not apply to NSP-Wisconsin or other utilities with less than 1 million customers in Michigan.

PSCo

Colorado Restructuring—During 1998, a bill was passed in Colorado that established an advisory panel to conduct an evaluation of electric industry restructuring and customer choice. During 1999, this panel concluded that Colorado would not significantly benefit from opening its markets to retail competition.

SPS

New Mexico Restructuring—In April 1999, New Mexico enacted the Electric Utility Restructuring Act of 1999, which provides for customer choice. The legislation provides for recovery of no less than 50 percent of stranded costs for all utilities. Transition costs must be approved by the NMPRC prior to being recovered through a non-bypassable wires charge, which must be included in transition plan filings. SPS must separate its utility operations into at least two entities: energy generation and competitive services, and transmission and distribution utility services, either by the creation of separate affiliates that may be owned by a common holding company or by the sale of assets to one or more third parties. A regulated company, in general, is prohibited from providing unregulated services. In May 2000, the NMPRC approved:

- customer choice for residential, small commercial and educational customers by January 2002;
- customer choice for commercial and industrial customers by July 2002; and
- completion of SPS corporate separation by August 2001.

The NMPRC has reopened its electric restructuring rulemakings to consider the impacts on New Mexico electricity markets arising from the volatile California electricity market conditions. In addition, in February 2001, the New Mexico Senate approved a bill that would delay the implementation of restructuring and retail choice until 2007. The House has yet to act on the proposal to delay. We cannot predict the changes that may result from reconsideration of the restructuring legislation or the NMPRC's reconsideration of its regulations as a result of the continuing and significant conditions in the California markets.

Texas Restructuring—In June 1999, an electric utility restructuring act (SB-7) was passed in Texas, which provides for the implementation of retail competition for most areas of the state, including SPS' service area, beginning January 2002. The PUCT can delay the date for full retail competition if a power region is unable to offer fair competition and reliable service during the 2001 pilot projects. The legislation requires:

- a rate freeze for all customers until January 2002;
- an annual earnings test through 2001;
- a 6-percent rate reduction for those residential and small commercial customers who choose not to switch suppliers at the start of retail competition;
- the unbundling of business activities, costs and rates relating to generation, transmission and distribution, and retail services;
- reductions in nitrogen oxide and sulfur dioxide emissions; and
- the recovery of stranded costs.

SB-7 requires each utility to unbundle its business activities into three separate legal entities: a power generation company, a regulated transmission and distribution company, and a retail electric provider. SB-7 limits the market share that a single generation provider can control to 20 percent of the generating capacity within a qualified power region. The establishment of a qualified power region with multiple generation suppliers is required under SB-7 in order to implement full retail competition. SPS must return any excess earnings indicated in the annual earnings tests above its last allowed rate of return for 1999, 2000 and 2001 or alternatively may direct any excess earnings to improvements in transmission and distribution facilities, to capital expenditures to improve air quality or to accelerate the amortization of regulatory assets, subject to PUCT approval.

The Texas Legislature is currently considering amendments to SB-7 that would delay the implementation of business separation and customer choice in SPS' market area for five years.

For more information on restructuring in Texas and New Mexico, see Note 12 to the Financial Statements under Item 8.

Kansas Restructuring—In 1999, the Kansas Corporation Commission investigated the adequacy of generation capacity of Kansas utilities. The Commission ordered the staff to continually monitor the generation capacity situation in Kansas, ensure the regular filing of information by utilities to meet their responsibility to provide electric service to retail customers and consider the opening of a new docket for conservation appeals.

Oklahoma Restructuring—The Electric Restructuring Act of 1997 was enacted in Oklahoma during 1997. This legislation directs a series of studies, which will define the orderly transition to consumer choice of electric energy supplier by July 1, 2002. The Electric Restructuring Act was modified during 1998 to clarify terms used in the original bill, as well as advance timelines for studies of the Joint Electric Utility Task Force in order to meet the stated implementation date. In 1998, this task force began the formation of groups, which will examine numerous restructuring issues. A report was issued in 1999. The 2001 legislative session will consider the task force’s findings as it considers issues related to implementing customer choice in 2002.

Other

Wyoming Restructuring—There were no electric industry restructuring legislation proposals introduced in the Legislature during 2000. No action with respect to electric restructuring is anticipated in 2001.

Capacity and Demand

Assuming normal weather during 2001, system peak demand and the net dependable system capacity for Xcel Energy’s electric utility subsidiaries are projected below. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin are managed as an integrated system (referred to as the NSP System). The system peak demand for each of the last three years and the forecast for 2001 is listed below.

<u>Operating company</u>	<u>System Peak Demand (Mw)</u>			
	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>
NSP System	7,660	7,990	7,936	7,747
PSCo	4,771	4,854	5,406	5,519
SPS	3,933	3,937	3,870	3,583
Cheyenne	140	144	146	153

The peak demand for the NSP System, PSCo and SPS all typically occurs in the summer. The 2000 system peak demand for the NSP System occurred on Aug. 14, 2000. The 2000 system peak demand for PSCo occurred on Aug. 9, 2000. The 2000 system peak demand for SPS occurred on Aug. 3, 2000. The system peak demand for the Cheyenne system occurs in the winter.

Energy Sources

Xcel Energy’s utility subsidiaries expect to use the following resources to meet their net dependable system capacity requirements: 1) Xcel Energy’s electric generating stations, 2) purchases from other utilities, independent power producers and power marketers, 3) demand-side management options and 4) phased expansion of existing generation at select power plants.

Purchased Power

Xcel Energy’s electric utility subsidiaries have contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. Capacity, typically measured in kilowatts or megawatts, is the measure of the rate at which a particular generating source produces electricity.

Energy, typically measured in kilowatt-hours or megawatt-hours, is a measure of the amount of electricity produced from a particular generating source over a period of time. Purchase power contracts typically provide for a charge for the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

The utility subsidiaries of Xcel Energy also make short-term and non-firm purchases to replace generation from company owned units that is unavailable due to maintenance and unplanned outages, to provide each utility's reserve obligation, to obtain energy at a lower cost than that which could be produced by other resource options, including company owned generation and/or long-term purchase power contracts, and for various other operating requirements.

NSP System Resource Plan

During 2000, NSP-Minnesota filed an electric resource plan for the NSP System with the MPUC for the period 2000 to 2015. The plan describes how Xcel Energy intends to meet the energy needs of the NSP System and includes an approximate schedule of the timing of resource solicitation to meet such needs. The plan contains conservation programs to reduce the NSP System's peak demand and conserve overall electricity use, an approximate schedule of power purchase solicitations to meet increasing demand and programs and plans to maintain the reliable operation of existing resources. In summary, the plan:

- forecasts 1.6-percent annual growth in the NSP System's energy and peak demand requirements;
- outlines NSP System's demand side management and conservation programs;
- shows new capacity needs of up to 600 megawatts by 2005 and 4,200 megawatts by 2015;
- describes the programs for achieving the mandated renewable energy sources of 425 megawatts of wind and 125 megawatts of biomass (NSP-Minnesota contracted for all 125 megawatts of biomass energy, but 80 megawatts of wind energy remains to be contracted); and
- updates the status of spent nuclear fuel at the Prairie Island plant and describes how it can continue to operate through the end of its license given different alternatives for storing spent nuclear fuel.

The resource plan proposes to satisfy the NSP System resource needs through the following energy source options:

- continued use of existing generation facilities, including the repowering of Black Dog Units 1 and 2;
- demand reduction of an additional 910 megawatts by 2015 through conservation and load management;
- 425 megawatts of wind energy and 125 megawatt of biomass energy under contract by 2002; and
- acquisition of competitively priced resources through competitive bidding.

The MPUC is currently reviewing this resource plan. Key issues are the amount of demand side management investment, nuclear spent fuel storage and its impact on future resource needs and assumptions made regarding unaccounted for operating costs of wind. NSP-Minnesota expects the MPUC to issue an order about this resource plan in mid-2001.

PSCo Resource Plan

PSCo estimates it will purchase approximately 37 percent of its total electric system energy input for 2001. Approximately 36 percent of the total system capacity for the summer 2001 system peak demand for PSCo will be provided by purchased power.

To meet the demand and energy needs of the rapidly growing economy in Colorado, PSCo recently completed a solicitation process that will add approximately 1,800 megawatts of resources to its system over the 2002-2005 time period. PSCo expects that purchased capacity will continue to meet a significant portion of system requirements at least through 2016.

Purchased Transmission Services

Xcel Energy’s electric utility subsidiaries have contractual arrangements with regional transmission service providers to deliver power and energy to the subsidiaries’ native load customers (retail and wholesale load obligations with terms of more than one year). Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved, although some agreements may base charges on the amount of metered energy delivered. Network transmission services include a charge for the metered demand at the delivery point at the time of the provider’s monthly transmission system peak, usually calculated as a 12-month rolling average.

Fuel Supply and Costs

The following tables present the delivered cost per million Btu of each category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the weighted average cost of all fuels during such years.

<u>NSP System Generating Plants:</u>	<u>Coal*</u>		<u>Nuclear</u>		<u>Average Fuel Cost</u>
	<u>Cost</u>	<u>Percent</u>	<u>Cost</u>	<u>Percent</u>	
2000	\$1.11	60%	\$0.45	36%	\$0.91
1999	1.10	58%	0.48	38%	0.88
1998	1.00	60%	0.47	35%	0.85

* Includes refuse-derived fuel and wood

<u>PSCo Generating Plants:</u>	<u>Coal</u>		<u>Gas</u>		<u>Average Fuel Cost</u>
	<u>Cost</u>	<u>Percent</u>	<u>Cost</u>	<u>Percent</u>	
2000	\$0.91	87%	\$3.97	13%	\$1.30
1999	0.90	92%	2.52	8%	1.04
1998	0.93	95%	2.46	5%	1.00

<u>SPS Generating Plants:</u>	<u>Coal</u>		<u>Gas</u>		<u>Average Fuel Cost</u>
	<u>Cost</u>	<u>Percent</u>	<u>Cost</u>	<u>Percent</u>	
2000	\$1.45	70%	\$4.23	30%	\$2.28
1999	1.41	70%	2.38	30%	1.70
1998	1.60	67%	2.19	33%	1.80

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin normally maintain between 20 and 40 days of coal inventory at each plant site. NSP-Minnesota and NSP-Wisconsin have long-term contracts providing for the delivery of up to 100 percent of 2001 coal requirements and up to 70 percent of their 2002 requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather and availability of equipment.

NSP-Minnesota and NSP-Wisconsin expect that all of the coal they burn in 2001 will have a sulfur content of less than 1 percent. NSP-Minnesota and NSP-Wisconsin have contracts for a maximum of 21.4 million tons of low-sulfur coal for the next two years. The contracts are with two Montana coal suppliers and four Wyoming suppliers. NSP-Minnesota and NSP-Wisconsin could purchase

approximately 5 percent of their coal requirements in the spot market in 2001 and 45 percent of coal requirements in 2002 if spot prices are more favorable than contracted prices.

Estimated coal requirements at NSP-Minnesota's major coal-fired generating plants and the coal supply for such requirements are approximately 12 million tons per year, which is covered by contracts with expiration dates that vary between 2001 and 2003.

NSP-Minnesota and NSP-Wisconsin's current fuel oil inventory is adequate and they have access to additional spot purchase supplies to meet anticipated 2001 requirements. Additional oil may be obtained through spot purchases.

To operate NSP-Minnesota's nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium- and long-term contracts for uranium, conversion and enrichment. Current contracts are flexible and cover 100 percent of uranium, conversion and enrichment requirements through the year 2001. These contracts expire at varying times between 2001 and 2005. The overlapping nature of contract commitments will allow NSP-Minnesota to maintain 50 percent to 100 percent coverage beyond 2001. NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Fuel fabrication is 100 percent committed through 2004 and 30 percent committed through 2010.

PSCo

PSCo's primary fuel for its steam electric generating stations is low-sulfur western coal. PSCo's coal requirements are purchased primarily under seven long-term contracts with suppliers operating in Colorado and Wyoming. During 2000, PSCo's coal requirements for existing plants were approximately 9.9 million tons, a substantial portion of which was supplied pursuant to long-term supply contracts. Coal supply inventories at Dec. 31, 2000, were approximately 33 days usage, based on the average burn rate for all of PSCo's coal-fired plants.

PSCo operates the Hayden Station, and has partial ownership in the Craig Station, in Colorado. All of Hayden Station's generating requirements are supplied under a long-term agreement. More than 75 percent of PSCo's Craig Station coal requirements are supplied under two long-term agreements. Any remaining Craig Station requirements for PSCo are supplied via spot coal purchases.

PSCo has secured more than 75 percent of Cameo Station's coal requirements for 2001 and 2002. Any remaining requirements may be purchased from this contract or the spot market. PSCo has contracted for long-term coal supplies to supply approximately 40 percent of the Cherokee and Valmont Stations' projected requirements in 2001. In addition, PSCo has contracted for substantially all of Cherokee's and Valmont's remaining projected 2001 coal needs.

PSCo has long-term coal supply agreements for the Pawnee and Comanche Stations' projected requirements. Under the long-term agreements, the supplier has dedicated specific coal reserves at the contractually defined mines to meet the contract quantity obligations. In addition, PSCo has a coal supply agreement to supply approximately 80 percent of Arapahoe Station's projected requirements for 2001. Any remaining Arapahoe Station requirements will be procured via spot purchases.

PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under short- and intermediate-term contracts to provide an adequate supply of fuel.

SPS

SPS purchases all of its coal requirements for Harrington and Tolk electric generating stations from TUCO Inc., in the form of crushed, ready-to burn coal delivered to SPS' plant bunkers. For the Harrington station the coal supply contract expires in 2016 and the coal-handling agreement expires in

2004. For the Tolk station, the coal supply contract expires in 2017 and the coal-handling agreement expires in 2005. At Dec. 31, 2000, coal inventories at the Harrington and Tolk sites were approximately 30 and 32 days supply, respectively. TUCO has a long-term coal supply agreement to supply approximately 55 percent of Harrington's projected requirements in 2001. TUCO has long term contracts for supply of coal in sufficient quantities to meet the primary needs of the Tolk station.

SPS has a number of short and intermediate contracts with natural gas suppliers operating in gas fields with long life expectancies in or near its service area. SPS also utilizes firm and interruptible transportation to minimize fuel costs during volatile market conditions and to provide reliability of supply. SPS maintains sufficient gas supplies under short- and intermediate-term contracts to meet all power plant requirements; however, due to flexible contract terms, approximately 55 percent of SPS' gas requirements during 2000 were purchased under spot agreements.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974 and are licensed to operate until 2013 and 2014, respectively.

Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive waste includes used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that has become contaminated through use in the plant.

Federal law places responsibility on each state for disposal of its low-level radioactive waste. Low-level radioactive waste from NSP-Minnesota's Monticello and Prairie Island nuclear plants is currently disposed of at the Barnwell facility, located in South Carolina (all classes of low-level waste), and the Clive facility, located in Utah (class A low-level waste only). Chem Nuclear is the owner and operator of the Barnwell facility, which has been given authorization by South Carolina to accept low-level radioactive waste from out of state. Envirocare, Inc. operates the Clive facility. NSP-Minnesota and Barnwell currently operate under an annual contract, while NSP-Minnesota uses the Envirocare facility through various low-level waste processors. NSP-Minnesota has low-level storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their licensed life, if off-site low-level disposal facilities were not available to NSP-Minnesota.

The federal government has the responsibility to dispose of, or permanently store, domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the Department of Energy (DOE) to implement a program for nuclear waste management. This includes the siting, licensing, construction and operation of a repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent storage or disposal facility by 1998. None of NSP-Minnesota's spent nuclear fuel has yet been accepted by the DOE for disposal. See Item 3—Legal Proceedings and Note 15 to the Financial Statements under Item 8 for further discussion of this matter.

NSP-Minnesota has on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear plants. NSP-Minnesota has expanded the used nuclear fuel storage facilities at its Monticello plant by replacement of the racks in the storage pool and by shipping 1,058 used fuel assemblies to a General Electric storage facility. The Monticello plant is expected to have sufficient pool storage capacity to the end of its current operating license in 2010.

The Prairie Island spent fuel pool has undergone two storage rack replacements. The on-site storage pool for spent nuclear fuel at Prairie Island was nearly filled and adequate space was no longer available. In 1994, a Minnesota law was enacted authorizing NSP-Minnesota to install 17 spent fuel casks for storage of spent nuclear fuel at Prairie Island. NSP-Minnesota has determined 17 casks will allow facility operation until 2007. As of Dec. 31, 2000, 12 storage casks were loaded and stored on the

Prairie Island nuclear generating plant site. The Minnesota Legislature established several energy resource requirements and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. NSP-Minnesota has implemented programs to meet the legislative commitments.

NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 1997, Private Fuel Storage LLC (PFS) filed a license application with the Nuclear Regulatory Commission (NRC) for a national temporary storage site for spent nuclear fuel. The PFS will undertake the development, licensing, construction and operation of a storage facility on the Skull Valley Indian Reservation in Utah. The NRC license review process consists of formal evidentiary hearings and opportunity for public input. Storage cask certification efforts are continuing, with one cask vendor on track to meet the project goals. The interim used fuel storage facility could be operational and able to accept the first shipment of spent nuclear fuel by 2004. However, due to uncertainty regarding regulatory and governmental approvals, it is possible that this interim storage may be delayed or not available at all.

In March 2001, NSP-Minnesota signed a contract with Steam Generator Team Ltd. to perform engineering and construction services for the installation of replacement generators at the Prairie Island nuclear power plant. NSP-Minnesota is evaluating the economics of replacing two 25-year-old steam generators on unit 1 at the plant. NSP-Minnesota is taking steps to preserve the replacement option for as early as 2004. The total cost of replacing the steam generators is estimated to be approximately \$132 million.

The NRC has issued a number of regulations, bulletins and orders that require analyses, modification and additional equipment at commercial nuclear power plants. The NRC is engaged in various ongoing studies and rulemaking activities that may impose additional requirements upon commercial nuclear power plants. Management is unable to predict any new requirements or their impact on NSP-Minnesota's facilities and operations.

Nuclear Management Company (NMC)

During 1999, NSP-Minnesota, Wisconsin Electric Power Co., Wisconsin Public Service Corp. and Alliant Energy established the NMC. The four companies operate seven nuclear units at five sites, with a total generation capacity exceeding 3,650 megawatts.

During the second quarter of 2000, the Nuclear Regulatory Commission (NRC) approved requests by NMC's four affiliated utilities to transfer operating authority for their five nuclear plants to NMC. NMC responsibilities will include oversight of on-site dry storage facilities for used nuclear fuel at the Point Beach and Prairie Island nuclear plants. Utility plant owners will continue to own the plants, control all energy produced by the plants and retain responsibility for nuclear liability insurance and decommissioning costs. Existing personnel will continue to provide day-to-day plant operations, with the additional benefit of tapping into ideas from all NMC-operated plants for improved safety, reliability and operational performance.

During the third quarter of 2000, NMC and Consumers Energy (CE) reached an agreement for the NMC to operate CE's 789-megawatt Palisades nuclear plant in Covert, Mich. The addition of Palisades gives NMC 4,500 megawatts of generation, making it the sixth largest operator of nuclear plants in the United States.

For further discussion of nuclear issues, see Note 14 and Note 15 to the Financial Statements under Item 8.

Electric Operating Statistics (Xcel Energy)

	Year Ended Dec. 31,		
	2000	1999	1998
Electric Sales (Millions of Kwh):			
Residential	22,101	20,681	20,358
Commercial	24,575	21,474	20,301
Industrial	32,834	32,862	33,776
Public Authorities and other	1,184	1,111	1,187
Total Retail	80,694	76,128	75,622
Sales for resale	26,284	21,001	22,736
Total Energy Sold	106,978	97,129	98,358
Number of Customers at End of Period:			
Residential	2,691,505	2,640,010	2,600,155
Commercial	370,840	367,967	346,348
Industrial	9,944	10,993	23,193
Public Authorities	98,715	96,098	90,053
Total Retail	3,171,004	3,115,068	3,059,749
Wholesale	220	189	395
Total Customers	3,171,224	3,115,257	3,060,144
Electric Revenues (Thousands of Dollars):			
Residential	\$ 1,607,655	\$ 1,526,148	\$ 1,496,225
Commercial	1,367,624	1,233,607	1,165,938
Industrial	1,404,926	1,424,328	1,473,325
Public Authorities and other	94,653	91,425	94,466
Conservation accrual adjustment	—	(71,348)	6,673
Total Retail	4,474,858	4,204,160	4,236,627
Wholesale	1,166,613	566,971	699,333
Other Electric Revenues	38,454	150,481	48,272
Total Electric Utility Revenues	\$ 5,679,925	\$ 4,921,612	\$ 4,984,232
Kwh Sales per Retail Customer	25,448	24,439	24,715
Revenue per Retail Customer	\$ 1,411.18	\$ 1,349.62	\$ 1,384.63
Residential Revenue per Kwh	7.27¢	7.38¢	7.35¢
Commercial Revenue per Kwh	5.57¢	5.74¢	5.74¢
Industrial Revenue per Kwh(1)	4.28¢	4.33¢	4.36¢
Wholesale Revenue per Kwh	4.44¢	2.70¢	3.08¢

GAS UTILITY OPERATIONS

Competition and Industry Restructuring

In the early 1990's, the FERC issued Order No. 636, which mandated unbundling interstate natural gas pipeline services—sales, transportation, storage and ancillary services. The implementation of Order No. 636 has resulted in additional competitive pressure on all local distribution companies (LDC) to keep gas supply and transmission prices for their large customers competitive. Customers have greater ability to buy gas directly from suppliers and arrange their own pipeline and LDC transportation service. Changes in regulatory policies and market forces have shifted the industry from traditional bundled gas sales service to an unbundled transportation and market based commodity service.

The natural gas delivery or transportation business has remained competitive as industrial and large commercial customers have the ability to bypass the local gas utility through the construction of

interconnections directly with, and the purchase of gas directly from, interstate pipelines, thereby avoiding the delivery charges added by the local gas utility. The gas utility subsidiaries of Xcel Energy have and will continue to aggressively pursue the retention of all customers on their systems.

NSP-Minnesota and NSP-Wisconsin provide unbundled transportation service to large customers. Transportation service does not have an adverse effect on earnings because NSP-Minnesota and NSP-Wisconsin's sales and transportation rates have been designed to make NSP-Minnesota and NSP-Wisconsin economically indifferent to whether gas has been sold and transported or merely transported. However, some transportation customers may have greater opportunities or incentives to physically bypass the LDC distribution system.

PSCo provides unbundled transportation service to large customers. and has participated fully in state regulatory and legislative efforts to develop a framework for extending unbundling down to the residential and small commercial level. PSCo supported a gas unbundling bill, passed by the Colorado Legislature in 1999, that provides the CPUC the authority and responsibility to approve voluntary unbundling plans submitted by Colorado gas utilities in the future. PSCo has not filed a plan to open its natural gas supply business to competition and continues to evaluate its business opportunities for doing so.

PSCo and Cheyenne extend and operate their distribution systems primarily by virtue of non-exclusive franchises granted by the various cities and towns. Their respective state commissions approve such franchise agreements. Because the franchises are non-exclusive, PSCo and Cheyenne can be faced with the threat of intrusion into their gas territory by third parties. PSCo holds territorial certificates for a portion of their gas service territory, giving them the exclusive right to extend their distribution system and provide natural gas sales and transportation service. However, for the majority of their gas service territory, no such territorial certificates exist. PSCo has filed with the CPUC an application to certify its gas service territory along the front range of Colorado. PSCo is pursuing settlement negotiations and expects a resolution during 2001.

Capability and Demand

NSP-Minnesota and NSP-Wisconsin

Xcel Energy categorizes its gas supply requirements as firm or interruptible (customers with an alternate energy supply). The maximum daily sendout (firm and interruptible) for the combined system of NSP-Minnesota and NSP-Wisconsin was 730,026 mmBtu for 2000, which occurred on Dec. 11, 2000.

NSP-Minnesota and NSP-Wisconsin purchase gas from independent suppliers. The gas is delivered under gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 630,000 mmBtu/day. In addition, NSP-Minnesota and NSP-Wisconsin have contracted with providers of underground natural gas storage services. Using storage reduces the need for firm pipeline capacity. These storage agreements provide storage for approximately 16 percent of annual and 23 percent of peak daily, firm requirements of NSP-Minnesota and NSP-Wisconsin.

NSP-Minnesota and NSP-Wisconsin also own and operate two liquefied natural gas (LNG) plants with a storage capacity of 2.5 bcf equivalent and four propane-air plants with a storage capacity of 1.4 bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 mcf of natural gas per day, or approximately 32 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days and can be used to minimize daily imbalance fees on interstate pipelines.

Gas utilities in Minnesota are required to file for a change in gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or exchange one form of demand for another. In July 2000, the MPUC approved NSP's 1999-2000 entitlement levels, which allow NSP-Minnesota to recover the demand entitlement costs associated with the increase in transportation

and storage levels in its monthly PGA. NSP-Minnesota's filing for approval of its 2000-2001 entitlement levels is pending MPUC action.

PSCo and Cheyenne

PSCo and Cheyenne project peak day gas supply requirements for firm sales and backup transportation (transportation customers contracting for firm supply backup) to be 1,639,899 mmBtu. In addition, firm transportation customers hold 379,882 mmBtu of capacity without supply backup. Total firm delivery obligations for PSCo and Cheyenne are 2,019,781 mmBtu per day. The maximum daily deliveries for both companies for 2000 (firm and interruptible services) were 1,612,589 mmBtu on Dec. 11, 2000.

PSCo and Cheyenne purchase gas from independent suppliers. The gas supplies are delivered to the respective delivery systems through a combination of transportation agreements with interstate pipelines and deliveries by suppliers directly to each company. These agreements provide for firm deliverable pipeline capacity of 1,193,821 mmBtu/day, which includes 731,960 mmBtu of supplies held under third-party storage agreements. In addition, PSCo operates three company-owned storage facilities, which provide about 147,980 mmBtu of gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at the companies' citygate meter stations and a small amount received directly from wellhead sources.

PSCo has received approval to abandon one of its three storage facilities, Leyden Storage Field, beginning October 2001. The field's 110,000 mmBtu peak day capacity will be replaced in 2001 with additional third-party storage and transportation capacity.

PSCo is required by CPUC regulations to file a gas purchase plan by June of each year projecting and describing the quantities of gas supplies, upstream services and the costs of those supplies and services for the period beginning July 1 through June 30 of the following year. PSCo is also required to file a gas purchase report by October of each year reporting actual quantities and costs incurred for gas supplies and upstream services for the 12-month period ending the previous June 30. PSCo has filed the required Plans with the CPUC, which is reviewing the gas purchase report for the period July 1, 1999, through June 30, 2000.

Gas Supply and Costs

Xcel Energy's gas utilities actively seek gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. This diversification involves numerous domestic and Canadian supply sources, with varied contract lengths.

The following table summarizes the average cost per mmBtu of gas purchased for resale by Xcel Energy's regulated retail gas distribution business.

	<u>NSP-Minnesota</u>	<u>NSP-Wisconsin</u>	<u>PSCo</u>	<u>Cheyenne</u>
2000	\$4.56	\$4.71	\$4.48	\$4.03
1999	\$2.97	\$3.32	\$2.85	\$2.57
1998	\$2.83	\$3.18	\$2.64	\$2.45

The cost of gas supply, transportation service and storage service is recovered through various cost recovery adjustment mechanisms.

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin have firm gas transportation contracts with several pipelines, which expire in various years from 2001 through 2013. Approximately 80 percent of NSP-Minnesota and NSP-Wisconsin's retail gas customers are served from the Northern Natural pipeline system.

In addition to fixed transportation charge obligations, NSP-Minnesota and NSP-Wisconsin have entered into firm gas supply agreements that provide for the payment of monthly or annual reservation charges irrespective of the volume of gas purchased. The total annual obligation is approximately \$18 million. These agreements allow NSP-Minnesota and NSP-Wisconsin to purchase natural gas at a high load factor at rates below the prevailing market price, reducing the total cost per mmBtu.

NSP-Minnesota and NSP-Wisconsin have certain gas supply and transportation agreements that include obligations for the purchase and/or delivery of specified volumes of gas or to make payments in lieu of delivery. At Dec. 31, 2000, NSP-Minnesota and NSP-Wisconsin were committed to approximately \$221 million in such obligations under these contracts, which range from the years 2001-2013. NSP-Minnesota and NSP-Wisconsin have negotiated market out clauses in their new supply agreements, which reduce purchase obligations if NSP-Minnesota and NSP-Wisconsin no longer provide merchant gas service.

NSP-Minnesota and NSP-Wisconsin purchase firm gas supply from approximately 30 domestic and Canadian suppliers under contracts with durations of one year to 10 years. NSP-Minnesota and NSP-Wisconsin purchase no more than 20 percent of their total daily supply from any single supplier. This diversity of suppliers and contract lengths allows NSP-Minnesota and NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

NSP-Minnesota and NSP-Wisconsin have completed substantially all of their obligations related to gas supply transportation and storage contracts that resulted from FERC Order 636.

PSCo and Cheyenne

PSCo and Cheyenne have attempted to maintain low-cost, reliable natural gas supplies by optimizing a balance of long-term and short-term gas purchases, firm transportation and gas storage contracts. During 2000, PSCo and Cheyenne purchased natural gas from approximately 47 suppliers.

PSCo and Cheyenne have completed substantially all of their obligations related to gas supply transportation and storage contracts that resulted from FERC Order 636. PSCo and Cheyenne have entered into new contracts for firm transportation and gas storage services. Adequate supplies of natural gas are currently available for delivery within the region. PSCo and Cheyenne continually evaluate the natural gas markets and procure supplies, as needed, to meet current and anticipated customer demand.

Viking

During 1999, Viking, WICOR and CMS Energy Corp. announced plans to build an interstate natural gas pipeline to serve the growing needs of the northern Illinois and southeastern Wisconsin

markets. The three energy companies each own an equal share of the pipeline. The project, called the Guardian Pipeline, will transport natural gas from a hub near Joliet, Ill. to the Ixonia, Wis., area. In March 2001, the FERC issued a certificate of public convenience and necessity authorizing the construction and operation of the Guardian pipeline. The estimated cost of the 147-mile pipeline is \$230 million and is expected to be in operation by late 2002.

Gas Operating Statistics (Xcel Energy)

	Year Ended Dec. 31,		
	2000	1999	1998
Gas Deliveries (Thousands of Dth):			
Residential	137,989	125,694	121,674
Commercial and Industrial	96,370	91,064	89,203
Total Retail	234,359	216,758	210,877
Transportation and Other	297,041	272,757	276,656
Total Deliveries	<u>531,400</u>	<u>489,515</u>	<u>487,533</u>
Number of Customers at End of Period:			
Residential	1,483,114	1,436,455	1,388,933
Commercial and Industrial	143,568	146,090	138,077
Total Retail	1,626,682	1,582,545	1,527,010
Transportation and Other	3,233	3,152	2,796
Total Customers	<u>1,629,915</u>	<u>1,585,697</u>	<u>1,529,806</u>
Gas Revenues (Thousands of Dollars):			
Residential	\$ 878,638	\$ 691,612	\$ 662,073
Commercial and Industrial	506,040	375,814	367,213
Total Retail	1,384,678	1,067,426	1,029,286
Transportation and Other	84,202	74,003	80,718
Total Gas Revenues	<u>\$1,468,880</u>	<u>\$1,141,429</u>	<u>\$1,110,004</u>
Dth Sales per Retail Customer	144.07	136.97	138.09
Revenue per Retail Customer	\$ 851.23	\$ 674.50	\$ 674.05
Average Revenue per Dth:			
Residential	\$ 6.37	\$ 5.50	\$ 5.44
Commercial and Industrial	\$ 5.25	\$ 4.13	\$ 4.12
Transportation and Other	\$ 0.28	\$ 0.27	\$ 0.29

NONREGULATED SUBSIDIARIES

Through its non-utility subsidiaries, Xcel Energy invests and operates several nonregulated businesses in a variety of industries. The following is an overview of the significant nonregulated businesses.

NRG Energy, Inc.

NRG is a global energy company primarily engaged in the acquisition, development, ownership and operation of power generation facilities and the sale of energy, capacity and related products.

At Dec. 31, 2000, Xcel Energy indirectly owned 82 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter 2000, when NRG completed its initial public offering. During March 2001, NRG issued an additional 18.4 million shares of common stock, which caused Xcel Energy's ownership interest in NRG to decline to approximately 75 percent. For more information, see NRG Initial Public Offering discussed under Liquidity and Capital Resources in Management's Discussion and Analysis under Item 7.

At Dec. 31, 2000, NRG had interests in power generation facilities with a total generating capacity of 25,059 megawatts. Of this amount, NRG has a net ownership of 15,007 megawatts. NRG also has interests in district heating and cooling systems and steam generation and transmission operations. As of Dec. 31, 2000, these thermal businesses had a steam and chilled water capacity equivalent to approximately 1,506 megawatts, of which NRG's net ownership interest is 1,379 megawatts.

NRG conducts business domestically and internationally through various subsidiaries, including: NRG International, Inc.; NEO Corporation; NRG Energy Center, Inc; NRG Operating Services, Inc.; NRG Northeast Generating LLC; NRG South Central Generating LLC; and other businesses and affiliates.

NRG is pursuing several energy-related investment opportunities, including those discussed further, and continues to evaluate other opportunities as they arise. The following discussion describe NRG's significant business developments including pending asset acquisitions, which are subject to various regulatory approvals. Potential capital requirements for these opportunities are discussed in Management's Discussion and Analysis under Item 7. Additional information is included in Item 1 of NRG's 2000 Form 10-K, which is incorporated by reference via Exhibit 99.02.

NRG 2001 Business Developments

In March 2001, NRG agreed to purchase a 720-megawatt, winter-rated/640-megawatt, summer-rated simple-cycle plant, which uses natural gas and has dual-fuel capability. The project is currently under construction in Missouri and is expected to enter commercial operation in June 2001. NRG expects to close the acquisition during 2001.

In January 2001, NRG acquired a 5,633-megawatt portfolio of operating projects and projects in construction and advanced development, located in the central United States, from LS Power, LLC for approximately \$708 million. NRG owns 100 percent of this project.

NRG 2000 Business Developments

In January 2000, NRG agreed to purchase 1,875 megawatts of fossil-fueled electric generation assets in the Mid-Atlantic region of the United States from Conectiv. The purchase price is approximately \$800 million. NRG will sell 500 megawatts of energy around the clock to Delmarva Power and Light Company under a five-year agreement. The remaining energy and capacity will be sold into the markets in the Mid-Atlantic region. NRG will own a 100 percent of this project. NRG expects to close the acquisition in the second quarter of 2001.

In February 2000, NRG executed a memorandum of understanding with GE Power Systems, a division of General Electric Company, to purchase 11 gas turbine generators and five steam turbine

generators over the next five years for approximately \$500 million. NRG intends to install the 16 turbines, having a combined capacity of 3,000 megawatts at its existing North American plant sites.

In March 2000, NRG purchased 1,708 megawatts of fossil-fueled generation from Cajun Electric Power Cooperative for approximately \$1 billion. The output from the base-load Cajun facility will be sold principally under long-term contracts. NRG owns 100 percent of this project.

In March 2000, NRG purchased the 680-megawatt Killingholme A station from National Power plc. for approximately 390 million pounds sterling (approximately \$615 million based on exchange rates at the time of acquisition). Killingholme A was commissioned in 1994 and is a combined-cycle, gas-turbine power station located in England. NRG owns 100 percent of this project.

During August 2000, NRG signed an agreement with Eesti Energia, the Estonian state-owned electric utility, providing for the purchase of a 49-percent interest in Narva Power, the owner and operator of the oil shale-fired Eesti and Balti power plants located near Narva, Estonia. The plants have a combined capacity of approximately 2,700 megawatts. The purchase price is approximately \$66 million. NRG expects to close the acquisition in the third quarter of 2001.

During September 2000, NRG acquired a 100-year lease of the Flinders Power assets in South Australia for approximately AUD \$314 million (approximately \$180 million U.S. at time of purchase). Flinders Power includes two power stations totaling 760 megawatts, the Leigh Creek coal mine, a dedicated rail line between the two, and Leigh Creek township. NRG owns 100 percent of this project.

In October 2000, NRG agreed to purchase a 50-percent interest in Sierra Pacific Resources' 522-megawatt coal-fired North Valmy Generating Station and a 100-percent interest in 25 megawatts of peaking units near Valmy Station for approximately \$273 million. The Valmy assets are currently owned by Sierra Pacific Resources' subsidiary, Sierra Pacific Power Company. The agreement includes a transitional power purchase agreement for Sierra Pacific Power to purchase energy and ancillary services through March 2003. The acquisition is expected to close during 2001.

In November 2000, NRG and Dynegy Inc. agreed to acquire the 740-megawatt, gas-fired Clark Generating Station and 445 megawatts of the 605-megawatt, coal-fired Reid Gardner Generating Station from Sierra Pacific Resources for approximately \$634 million. The facilities serve the Las Vegas market. The agreements include a transitional power purchase agreement for Nevada Power to purchase energy and ancillary services until March 2003. The transaction is expected to close during 2001. NRG will own 50 percent of this project.

In November 2000, NRG, through subsidiaries, joined the SRW Cogeneration Limited Partnership. The limited partnership owns and will operate the 420-megawatt, natural gas-fired cogeneration plant now under construction at the DuPont Company's Sabine River Works petrochemical facility near Orange, Texas. NRG expects the plant to begin commercial operations in the summer of 2001. Bechtel Energy Corporation is the construction contractor. Electricity and all the steam generated by the power plant will be sold to the adjacent DuPont Sabine River Works facility. Additional electricity will be sold on the merchant market. NRG will own 50 percent of the \$260 million facility.

In December 2000, NRG agreed to acquire the Bridgeport and New Haven Harbor Stations in Connecticut from Wisconsin Energy Corp. for approximately \$325 million. The purchase will add 1,051 megawatts to NRG's portfolio. NRG plans to seek approval for adding pollution control technology to the Bridgeport Harbor Station. The transaction is expected to close during the second quarter of 2001. NRG will own 100 percent of this project.

NRG 1999 Business Developments

In April 1999, NRG acquired the Somerset power station for approximately \$55 million from Eastern Utilities Associates (EUA). The Somerset station, located in Somerset, Mass., includes two coal-fired generating facilities and two combustion turbine peaking units with a capacity rating of 160 megawatts. NRG owns a 100 percent of this project. NRG entered into a Wholesale Standard Offer

Service Agreement in which NRG is obligated to provide approximately 30 percent of the energy and capacity requirements of certain EUA affiliates (approximately 275 megawatts at peak requirement) until December 2009.

In May 1999, NRG and Dynegy acquired the Encina generating station and 17 combustion turbines for approximately \$356 million from San Diego Gas & Electric Company. The facilities, which have a combined capacity of 1,218 megawatts, are located near Carlsbad and San Diego, Calif. NRG and Dynegy each own a 50-percent interest.

In June 1999, NRG acquired the Huntley and Dunkirk generating stations from Niagara Mohawk Power Corp. (NIMO) for approximately \$355 million. The two coal-fired plants are located near Buffalo, N.Y., and have a combined summer capacity of 1,360 megawatts. NRG owns a 100 percent of this project. In connection with this acquisition, NRG entered into several transition power purchase agreements in which NIMO will purchase energy and capacity from these facilities for four years. NRG agreed to sell 100 percent of the capacity of and up to 39 percent of the annual energy output from the Dunkirk facility to NIMO at fixed prices.

In June 1999, NRG acquired the Arthur Kill generating station and the Astoria gas turbine site for approximately \$505 million from Consolidated Edison Company (ConEd). These facilities, which are located in the New York City area, have a combined summer capacity of 1,456 megawatts. NRG owns a 100 percent interest in these projects. NRG agreed to sell to ConEd energy from the Arthur Kill and Astoria facilities at a fixed price in varying amounts, as specified by ConEd, up to the full capability of each facility. In addition, NRG has agreed to sell to ConEd at a fixed price, during certain periods, up to 100 percent of the capacity of the Arthur Kill generating facility and Astoria gas turbines facility.

In October 1999, NRG purchased the 1,700-megawatt, oil and gas-fired Oswego generating station, located in Oswego, N.Y., for approximately \$85 million from NIMO and Rochester Gas and Electric Corporation. NRG owns a 100 percent of this project.

In December 1999, NRG purchased gas and oil electric generating stations with a combined capacity of 2,235 megawatts for \$460 million from Connecticut Light & Power Company (CL&P). The facilities are located throughout Connecticut. NRG owns a 100 percent of this project. NRG entered into a Standard Offer Service Wholesale Sales Agreement with CL&P. NRG will supply CL&P with 40 percent of its standard offer service load during 2001 and 2002, and 45 percent during 2003.

In December 1999, NRG purchased a 50-percent interest in the Rocky Road Power Plant, a 250-megawatt, natural gas-fired simple-cycle peaking facility in East Dundee, Ill., from Dynegy Inc. for approximately \$60 million. In June 2000, the installation of an additional 100-megawatt natural gas combustion turbine was completed, increasing the facility's generating capacity to 350 megawatts.

In December 1999, NRG sold a portion of its ownership interest in Cogeneration Corp. of America to Calpine Corp. This sale reduced NRG's ownership stake in CogenAmerica from 45 percent to 20 percent.

Significant NRG Nonregulated Generation Projects Operating at Dec. 31, 2000

Generation Projects Operating	Location	Total Mw	NRG Ownership	Mw-Equity	Operator
NRG Northeast Generating LLC	USA	6,980	100.00%	6,980	NRG
NRG South Central Generating LLC .	USA	1,708	100.00%	1,708	NRG
West Coast Power LLC	USA	2,512	50.00%	1,256	Southern California Edison
Flinders Power	Australia	760	100.00%	760	NRG
Killingholme	UK	680	100.00%	680	NRG
Gladstone Power Station	Australia	1,680	37.50%	630	NRG
Loy Yang Power A	Australia	2,000	25.37%	507	NRG/CMS Generation
Schkopau Power Station(1)	Germany	960	20.95%	200	PreussenElektraKraftwerk AG
Rocky Road Power	USA	350	50.00%	175	Dynegy
Crockett Cogeneration	USA	240	57.67%	138	NRG
San Diego Combustion Turbines	USA	253	50.00%	127	NRG
COBEE (Bolivian Power Co. Ltd.) . .	Bolivia	219	49.10%	108	COBEE
Cogeneration of America(2)	USA	575	20.00%	99	NRG
Enfield Energy Centre	UK	396	25.00%	99	NRG/Indeck
Energy Developments Limited	Australia	274	29.14%	79	Energy Development Limited
MIBRAG mbH	Germany	233	33.33%	78	MIBRAG
Scudder Latin American Power(3) . .	Latin America	772	6.63%	51	Stewart & Stevenson/Wartsila

(1) Through a lease agreement, NRG has ownership of 200 megawatts.

(2) Cogeneration Corp. owns various percentages of projects, making NRG's share of ownership 99 megawatts.

(3) Scudder owns various percentages of projects, making NRG's share of ownership 51 megawatts.

Yorkshire Power

Yorkshire Power is a joint venture, equally owned by Xcel International and a subsidiary of American Electric Power Company, which acquired indirectly all of the outstanding ordinary shares of Yorkshire Electricity, a U.K. regional electricity company, for approximately \$362 million in April 1997. Yorkshire Electricity's main businesses are the distribution and supply of electricity and the supply of gas. Its service territory is one of the region's largest with approximately 2 million customers.

In late February 2001, Xcel Energy reached an agreement in principle to sell at book value all of its investment in Yorkshire Power, except for an interest of approximately 5.25 percent, to Innogy Holdings plc. Xcel Energy is retaining this interest to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. The sale is conditional on the approval of Innogy shareholders. Following completion of the transaction, proceeds of the sale will be used by Xcel Energy to pay down short-term debt and eliminate the need for an equity issuance planned for the second half of 2001.

Utility Engineering (UE)

UE was incorporated in 1985 under the laws of Texas. UE is engaged in engineering, design, construction management and other miscellaneous services. UE currently has five wholly-owned subsidiaries—Universal Utility Services LLC, Precision Resource Company, Quixx, Proto-Power and Applied Power Associates Inc. Universal Utility Services Company provides cooling tower maintenance and repair, certain other industrial plant improvement services, and engineered maintenance of high-voltage plant electric equipment. Precision Resource Company provides contract professional and technical resources for customers in the energy industrial sectors. Quixx was incorporated in 1985 under the laws of Texas. Quixx's primary business is investing in and developing cogeneration and energy-related projects. Quixx also holds water rights and certain other non-utility assets. Quixx financed the sale of heat pumps until December 1999.

e prime, inc.

e prime was incorporated in 1995 under the laws of Colorado. e prime provides energy related products and services, which include natural gas marketing and trading and energy consulting. In 1996, e prime received authorization from the FERC to act as a power marketer. Additionally, e prime owns Young Gas Storage Company, which owns a 47.5 percent general partnership interest in an underground gas storage facility in northeastern Colorado. e prime also holds a 50-percent ownership interest in Johnstown Cogeneration, a limited liability company.

Planergy International Inc.

Planergy was acquired in 1998. Planergy provides energy management, consulting, on-site generation, load curtailment and demand-side management services to industrial, commercial and utility customers.

Energy Masters International, Inc. (EMI) began operations in 1993. EMI primarily offers retrofitting and upgrading facilities for greater energy efficiency on a national basis. In 1995, EMI acquired Energy Masters Corporation, a company that specializes in energy efficiency improvement services for commercial, industrial and institutional customers. In 1997, EMI acquired 100 percent of Energy Solutions International Inc., an energy management firm.

During the third quarter of 2000, Planergy and EMI, both wholly owned subsidiaries of Xcel Energy, were combined to form Planergy International.

Seren Innovations, Inc.

Seren was formed in 1996 to pursue communications and data services businesses. Currently, Seren is constructing a combination cable television, telephone and high-speed internet access system in two locations, St. Cloud, Minnesota and Contra Costa county in the east bay area of northern California. Seren had capitalized \$95 million for plant in service and had incurred another \$86 million for construction work in progress for these systems at Dec. 31, 2000. Seren continues to expand its systems and market to new customers in these areas. The ultimate viability of Seren is dependent on the success of securing a customer and revenue base sufficient to recover the capital investment and ongoing operating costs.

Eloigne Company

Eloigne was established in 1993 and its principal business is the acquisition of rental housing projects that qualify for low-income housing tax credits under current federal tax law. As of Dec. 31, 2000, approximately \$81 million had been invested in Eloigne projects, including approximately \$24 million in wholly owned properties and approximately \$57 million in equity interests in jointly-owned projects. These investments and related working capital requirements have been financed with approximately \$51 million of long-term debt and the remainder with equity capital.

Completed Eloigne projects as of Dec. 31, 2000, are expected to generate tax credits of \$73 million over the time period of 2001-2009. Tax credits recognized in 2000 as a result of these investments were approximately \$10.4 million.

Independent Power Corporation/Independent Power International (IPC/IPI)

Xcel Energy has a 49.9 percent equity interest in IPC/IPI, which is based in Denver, Colo. IPC/IPI currently owns and operates three plants in Argentina with an installed generating capacity of 744 megawatts with a further 800 megawatts of capacity under development. During 2000, IPC/IPI purchased Fawley Power Station, which comprises four 500 MW oil-fired steam generating units, of which only one is currently operational. Over the past seven years the station has been operated primarily in peaking mode. The plant is located in England.

ENVIRONMENTAL MATTERS

Certain of Xcel Energy's subsidiary facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Company facilities have been designed and constructed to operate in compliance with applicable environmental standards.

Xcel Energy and its subsidiaries strive to comply with all environmental regulations applicable to its operations. However, it is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, generally, what effect future laws or regulations may have upon Xcel Energy's operations. For more information on Environmental Matters, see Note 14 to the Financial Statements under Item 8 and Management's Discussion and Analysis under Item 7.

CAPITAL SPENDING AND FINANCING

For a discussion of capital expenditures and funding sources, see Management's Discussion and Analysis under Item 7.

EMPLOYEES

The number of Xcel Energy employees at Dec. 31, 2000, is presented in the table below. Of the employees listed below, approximately 6,900, or 44 percent, are covered under collective bargaining agreements.

NSP-Minnesota	4,575
NSP-Wisconsin	949
PSCo	2,779
SPS	1,189
Xcel Energy Service Co.	2,219
Other subsidiaries	<u>4,101</u>
Total	<u>15,812</u>

EXECUTIVE OFFICERS

James J. Howard, 65, Chairman of the Board, Xcel Energy, August 2000 to present. Previously, Chairman of the Board, President and Chief Executive Officer of NSP since December 1994.

Wayne H. Brunetti, 58, President and Chief Executive Officer, August 2000 to present. Previously, Vice Chairman, President, Chief Operating Officer and Director of NCE since 1997 and President and Director of PSCo since 1994.

Paul J. Bonavia, 49, President—Energy Markets, Xcel Energy, August 2000 to present. Previously, Senior Vice President and General Counsel of NCE since 1997.

Cathy J. Hart, 51, Vice President and Corporate Secretary, Xcel Energy, August 2000 to present. Previously, Secretary of NCE since 1998 and Manager of Corporate Communications of PSCo from 1993 to 1996.

Gary R. Johnson, 54, Vice President and General Counsel, Xcel Energy, August 2000 to present. Previously, Vice President and General Counsel of NSP since 1991.

Richard C. Kelly, 54, President—Enterprises, Xcel Energy, August 2000 to present. Previously, Executive Vice President and Chief Financial Officer for NCE from 1997 to August 2000 and Senior Vice President of PSCo from 1990 to 1997.

Cynthia L. Leshner, 52, Vice President and Chief Administrative Officer, Xcel Energy, August 2000 to present. Previously, President of NSP-Gas since July 1997 and previously Vice President-Human Resources of NSP.

Edward J. McIntyre, 50, Vice President and Chief Financial Officer, Xcel Energy, August 2000 to present. Previously, Vice President and Chief Financial Officer of NSP since 1993.

Paul E. Pender, 46, Vice President and Treasurer, Xcel Energy, August 2000 to present. Previously, Vice President of Finance and Treasurer of NSP since May 1997 and previously Assistant Treasurer and Director of Corporate Finance of NSP.

Tom Petillo, 56, President—Retail, Xcel Energy, August 2000 to present. Previously, Executive Vice President of New Century Services from 1998 to August 2000 and President and Director of New Century International from 1997 to 1998.

David E. Ripka, 52, Vice President and Controller, Xcel Energy, August 2000 to present. Previously, Vice President and Controller of NRG from June 1999 to August 2000, Controller of NRG from March 1997 to June 1999 and Assistant Controller for NSP from June 1992 to March 1997.

David M. Wilks, 54, President—Energy Supply, Xcel Energy, August 2000 to present. Previously, Executive Vice President and Director of PSCo and New Century Services from 1997 to August 2000 and President, Chief Operating Officer and Director of SPS from 1995 to August 2000.

ITEM 2—PROPERTIES

For discussion and information concerning nonregulated properties, see “Nonregulated Subsidiaries” under Item 1, incorporated by reference.

Virtually all of the utility plant of NSP-Minnesota and NSP-Wisconsin is subject to the lien of their first mortgage bond indentures.

Electric utility generating stations:

NSP—Minnesota

<u>Station and Unit</u>	<u>Fuel</u>	<u>Installed</u>	<u>Summer 2000 Capability (Mw)</u>
Sherburne			
Unit 1	Coal	1976	712
Unit 2	Coal	1977	706
Unit 3	Coal	1987	522
Prairie Island			
Unit 1	Nuclear	1973	525
Unit 2	Nuclear	1974	524
Monticello	Nuclear	1971	572
King	Coal	1968	571
Black Dog			
2 Units	Coal/Natural Gas	1955-1960	284
High Bridge			
2 Units	Coal	1956-1959	269
Riverside			
2 Units	Coal	1964-1987	384
Other	Various	Various	1,080
		Total	<u>6,149</u>

NSP-Minnesota's 59 percent of Sherco unit 3's total capability

NSP — Wisconsin

<u>Station and Unit</u>	<u>Fuel</u>	<u>Installed</u>	<u>Summer 2000 Capability (Mw)</u>
Combustion Turbine:			
Flambeau Station	Natural Gas/Oil	1969	14
Wheaton			
6 Units	Natural Gas/Oil	1973	345
French Island			
2 Units	Oil	1974	154
Steam:			
Bay Front			
3 Units	Coal/Wood/Natural Gas	1945-1960	74
French Island			
2 Units	Wood/RDF	1940-1948	29
Hydro:			
19 Plants		Various	249
		Total . . .	<u>865</u>

RDF is refuse derived fuel, made from municipal solid waste

PSCo

<u>Station and Unit</u>	<u>Fuel</u>	<u>Installed</u>	<u>Summer 2000 Capability (Mw)</u>
Steam:			
Arapahoe			
4 Units	Coal	1950-1955	246
Cameo			
2 Units	Coal	1957-1960	73
Cherokee			
4 Units	Coal	1957-1968	717
Comanche			
2 Units	Coal	1973-1975	660
Craig			
2 Units	Coal	1979-1980	(a) 83
Hayden			
2 Units	Coal	1965-1976	(b) 237
Pawnee	Coal	1981	505
Valmont	Coal	1964	186
Zuni			
3 Units	Natural Gas/Oil	1948-1954	86
Combustion Turbines:			
Fort St. Vrain			
4 Units	Natural Gas	1979-98	465
Various Locations			
6 Units	Natural Gas	Various	159
Hydro:			
Various Locations			
14 Units(c)		Various	37
Cabin Creek Pumped Storage		1967	210
Diesel Generators:			
Cherokee			
2 Units		1967	6
		Total	<u>3,670</u>

(a) Based on PSCo ownership interest of 9.72 percent

(b) Based on PSCo ownership interest of 75.5 percent of unit 1 and 37.4 percent of unit 2

(c) Includes one station (2 units) not owned by PSCo but operated under contract

SPS

<u>Station and Unit</u>	<u>Fuel</u>	<u>Installed</u>	<u>Summer 2000 Capability (Mw)</u>
Steam:			
Harrington			
3 Units	Coal	1976-1980	1,066
Tolk			
2 Units	Coal	1982-1985	1,080
Jones			
2 Units	Natural Gas	1971-1974	486
Plant X			
4 Units	Natural Gas	1952-1964	442
Nichols			
3 Units	Natural Gas	1960-1968	457
Cunningham			
2 Units	Natural Gas	1957-1965	267
Maddox	Natural Gas	1983	118
CZ-2	Purchased Steam	1979	26
Moore County	Natural Gas	1954	48
Gas Turbine:			
Carlsbad	Natural Gas	1977	13
CZ-1	Hot Nitrogen	1965	13
Maddox	Natural Gas	1983	66
Riverview	Natural Gas	1973	23
Cunningham	Natural Gas	1998	220
		Total	<u>4,325</u>

Electric utility overhead and underground transmission and distribution lines at Dec. 31, 2000:

<u>Pole Miles</u>	<u>NSP-Minnesota</u>	<u>NSP-Wisconsin</u>	<u>PSCo</u>	<u>SPS</u>
500 kilovolt (kv)	265	0	0	0
345 kv	568	166	112	319
230 kv	284	0	1,683	1,582
161 kv	59	280	0	0
138 kv	0	0	65	
115 kv	1,206	449	772	2,459
Less than 115 kv	39,473	11,162	22,843	17,817

Electric utility transmission and distribution substations at Dec. 31, 2000:

<u>Quantity</u>	<u>NSP-Minnesota</u>	<u>NSP-Wisconsin</u>	<u>PSCo</u>	<u>SPS</u>
	349	205	367	304

Gas utility mains at Dec. 31, 2000:

<u>Miles</u>	<u>NSP-Minnesota</u>	<u>NSP-Wisconsin</u>	<u>PSCo</u>	<u>SPS</u>
Transmission	116	0	2,212	0
Distribution	8,384	1,870	16,253	0

ITEM 3—LEGAL PROCEEDINGS

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition for such matters.

On June 8, 1998, NSP-Minnesota filed a complaint in the Court of Federal Claims against the DOE requesting damages in excess of \$1 billion for the DOE's partial breach of the Standard Contract. NSP-Minnesota requested damages consisting of the costs of storage of spent nuclear fuel at the Prairie Island nuclear generating plant, anticipated costs related to the Private Fuel Storage, LLC and costs relating to the 1994 state legislation limiting the number of casks that can be used to store spent nuclear fuel at Prairie Island. On April 6, 1999, the Court of Federal Claims dismissed NSP-Minnesota's complaint. On May 20, 1999, NSP-Minnesota appealed to the Court of Appeals for the Federal Circuit. On Aug. 31, 2000, the Court of Appeals for the Federal Circuit reversed and remanded to the Court of Federal Claims. On Dec. 26, 2000, NSP-Minnesota filed a motion with the Court of Federal Claims to amend its complaint and renew its motion for summary judgment on the DOE's liability. These motions are pending before the Court of Federal Claims. On Jan. 9, 2001, the DOE filed a motion with the Chief Judge for the Court of Federal Claims asking that all cases against the DOE arising out of alleged breaches of the Standard Contract be reassigned to one judge. The DOE also asked for the extraordinary remedy of binding parties not currently party to an action before the Court of Claims to a determination in the proposed consolidated action. This motion is pending before the Court of Federal Claims.

In April 1997, a fire damaged several buildings in downtown Grand Forks, N. D., during a flood in the city. On July 23, 1998, the St. Paul Mercury Insurance Co. commenced a lawsuit against NSP-Minnesota for damages in excess of \$15 million. The suit was filed in the District Court in Grand Forks County in North Dakota. The insurance company alleged the fire was electrical in origin and that NSP-Minnesota was legally responsible for the fire because it failed to shut off electrical power to downtown Grand Forks during the flood and prior to the fire. Seven additional lawsuits were filed against NSP-Minnesota by insurance companies that insured businesses damaged by the fire. One additional lawsuit was filed by a bank. The total of damages sought by all these lawsuits was in excess of \$30 million. NSP-Minnesota denied any liability. On Sept. 8, 2000, the jury returned a defense verdict in favor of NSP-Minnesota. The plaintiffs did not appeal this verdict.

In 1997, NSP-Wisconsin was served with a summons and complaint on behalf of the owners of Schachtner Farms located in Deer Park, Wis. The complaint alleged that stray voltage from NSP-Wisconsin's system harmed their dairy herd, resulting in lost milk production, injury to the dairy herd, lost profits and increased veterinary expenses. On Nov. 23, 1999, the jury returned a verdict finding NSP-Wisconsin negligent and awarding Schachtner Farms \$850,000 for economic damages and \$200,000 for inconvenience, annoyance and loss of use and enjoyment of their property plus costs and interest. The Court trebled the damages because the jury found that NSP-Wisconsin was willful, wanton or reckless in its failure to provide adequate service to the farm. NSP-Wisconsin has appealed the decision to the Court of Appeals, Third District, of the State of Wisconsin. The claim was resolved on Dec. 20, 2000, on a confidential basis. NSP-Wisconsin's contribution to the settlement was reduced by insurance coverage.

For a discussion of other legal claims and environmental proceedings, see Note 14 to the Financial Statements under Item 8, incorporated by reference. For a discussion of proceedings involving utility rates, see "Regulatory Matters" under Item 1, and Management's Discussion and Analysis under Item 7, all incorporated by reference.

ITEM 4—SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None during the fourth quarter of 2000.

PART II

ITEM 5—MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Quarterly Stock Data

Xcel Energy's common stock is listed on the New York Stock Exchange (NYSE), Chicago Stock Exchange and the Pacific Stock Exchange. Following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2000 and 1999 and the dividends declared per share during those quarters

<u>Xcel Energy 2000</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
Third Quarter (from Aug. 18, 2000)	\$27.5625	\$24.0625	\$0.2178
Fourth Quarter	\$30.0000	\$24.6250	\$0.3750
<u>NCE 2000</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First Quarter	\$30.9375	\$24.0625	\$0.5800
Second Quarter	\$36.1875	\$29.6875	\$0.5800
Third Quarter (to Aug. 18, 2000)	\$35.0000	\$30.1250	\$0.1275
<u>NSP 2000</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First Quarter	\$20.5625	\$16.1250	\$0.3625
Second Quarter	\$23.8125	\$19.5000	\$0.3675
Third Quarter (to Aug. 18, 2000)	\$22.5000	\$20.1250	\$0.1588
<u>NCE 1999</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First Quarter	\$49.0625	\$33.6250	\$0.5800
Second Quarter	\$40.5625	\$33.3125	\$0.5800
Third Quarter	\$38.5625	\$31.9375	\$0.5800
Fourth Quarter	\$34.6875	\$30.3125	\$0.5800
<u>NSP 1999</u>	<u>High</u>	<u>Low</u>	<u>Dividends</u>
First Quarter	\$27.9375	\$23.0625	\$0.3575
Second Quarter	\$26.7500	\$22.5625	\$0.3625
Third Quarter	\$24.6875	\$20.9375	\$0.3625
Fourth Quarter	\$22.6875	\$19.3125	\$0.3625

Book value per share at Dec. 31, 2000, was \$16.32. Shareholders of record as of March 15, 2001, were 134,616.

Xcel Energy's Restated Articles of Incorporation and First Mortgage Bond Trust Indenture provide for certain restrictions on the payment of cash dividends on common stock. At Dec. 31, 2000, the payment of cash dividends on common stock was not restricted except as described in Note 9 to the Financial Statements under Item 8.

ITEM 6—SELECTED FINANCIAL DATA

<u>(Dollars in millions except per share data)</u>	<u>2000(d)</u>	<u>1999</u>	<u>1998</u>	<u>1997(e)</u>	<u>1996</u>
Operating revenues(a)	\$11,592	\$ 7,816	\$ 6,729	\$ 6,353	\$ 6,106
Operating expenses	\$10,021	\$ 6,614	\$ 5,654	\$ 5,329	\$ 4,991
Income before extraordinary item	\$ 546	\$ 571	\$ 624	\$ 499	\$ 547
Net income	\$ 527	\$ 571	\$ 624	\$ 388	\$ 547
Earnings available for common stock	\$ 523	\$ 566	\$ 619	\$ 377	\$ 535
Average number of common shares outstanding (000's)	337,832	331,943	323,883	303,042	296,862
Average number of common and potentially dilutive shares outstanding (000's)	338,111	332,054	324,355	303,422	297,166
Earnings per share before extraordinary item—basic	\$ 1.60	\$ 1.70	\$ 1.91	\$ 1.61	\$ 1.80
Earnings per share before extraordinary item—diluted	\$ 1.60	\$ 1.70	\$ 1.91	\$ 1.61	\$ 1.80
Earnings per share—basic	\$ 1.54	\$ 1.70	\$ 1.91	\$ 1.24	\$ 1.80
Earnings per share—diluted	\$ 1.54	\$ 1.70	\$ 1.91	\$ 1.24	\$ 1.80
Dividends declared per share(b)	\$ 1.45	\$ 1.47	\$ 1.46	\$ 1.53	\$ 1.39
Total assets	\$21,769	\$18,070	\$15,055	\$14,442	\$13,230
Long-term debt	\$ 7,583	\$ 5,827	\$ 4,057	\$ 3,867	\$ 3,472
Book value per share	\$ 16.32	\$ 15.78	\$ 15.44	\$ 14.74	\$ 14.41
Return on average common equity	9.6	10.9	12.6	8.4	12.7
Ratio of earnings to fixed charges(c)	1.9	2.4	3.0	2.6	3.6

(a) Revenues have been restated to reflect revenues on a gross basis.

(b) Amounts include proforma adjustments to restate periods prior to the Xcel Energy merger for historically consistent reporting. Dividends in 2000 and 1997 reflect dividends paid by predecessor companies before and successor companies after the Xcel Energy merger in August 2000 and the New Century Energies merger in August 1997.

(c) Excludes undistributed equity income and includes allowance for funds used during construction.

(d) Earnings in 2000 were reduced by 52 cents per share for special charges related to the merger of NSP and NCE. In addition, earnings in 2000 were reduced by 6 cents per share for extraordinary items related to electric utility restructuring in Texas and New Mexico, as discussed in Note 12 to the Financial Statements under Item 8.

(e) Earnings in 1997 were reduced by 16 cents per share for special charges related to the merger of PSCo and SPS and to write-off costs for the terminated merger to form Primergy. In addition, earnings in 1997 were reduced by 37 cents per share for an extraordinary item related to the UK windfall tax recorded at Yorkshire Power.

ITEM 7—MANAGEMENT’S DISCUSSION AND ANALYSIS

On Aug. 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act (PUHCA). Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares) and accounted for as a pooling-of-interests. As part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of Xcel Energy named Northern States Power Company.

Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); Southwestern Public Service Company (SPS); Black Mountain Gas Company (BMG); and Cheyenne Light, Fuel and Power Company (Cheyenne). Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy’s regulated businesses also include Viking Gas Transmission Company and WestGas InterState Inc. (WGI), both interstate natural gas pipeline companies.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., a publicly traded, independent power producer. Xcel Energy indirectly owns 82 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering. NRG expects to issue additional common stock during March 2001, which will cause Xcel Energy’s ownership interest in NRG to decline. For more information, see NRG Initial Public Offering discussed under Liquidity and Capital Resources.

In addition to NRG, Xcel Energy’s nonregulated subsidiaries include Seren Innovations, Inc. (broadband telecommunications services), e prime, inc. (natural gas marketing and trading), Planergy International, Inc. (energy management, consulting and demand-side management services) and Eloigne Company (acquisition of rental housing projects that qualify for low-income housing tax credits). Xcel Energy also reports in its nonregulated activities its 50-percent stake in Yorkshire Power, a regional electric company in the United Kingdom. Subsequent to year end, Xcel Energy has agreed to sell a substantial portion of this investment. For more information, see Note 11 to the Financial Statements.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Energy Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc. and Xcel Energy O & M Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

XCEL ENERGY’S MISSION AND GUIDING PRINCIPLES

Xcel Energy’s mission is to provide energy and service solutions that advance the productivity and lifestyle of our customers, foster growth of our employees and enhance value for our shareholders.

Xcel Energy’s guiding principles include: focusing on the customer, respecting people, managing with facts, continually improving our business, focusing on the prevention of problems and promoting a safe and challenging work environment.

FINANCIAL REVIEW

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy’s financial condition, results of operations and cash flows during the periods

presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying Financial Statements and Notes.

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “estimate,” “expect,” “objective,” “outlook,” “possible,” “potential” and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including their impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; the higher risk associated with Xcel Energy’s nonregulated businesses compared with its regulated businesses; currency translation and transaction adjustments; risks associated with the California power market; the items described under “Factors Affecting Results of Operations;” and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Exhibit 99.04 to Xcel Energy’s Report on Form 8-K dated Aug. 21, 2000.

RESULTS OF OPERATIONS

Xcel Energy’s earnings per share for the past three years were as follows:

Contribution to earnings per share

	<u>2000</u>	<u>1999</u>	<u>1998</u>
Total regulated earnings before extraordinary items	\$ 1.26	\$1.51	\$1.71
Total nonregulated	0.34	0.19	0.20
Extraordinary items (see Note 12)	<u>(0.06)</u>	<u>—</u>	<u>—</u>
Total earnings per share	<u>\$ 1.54</u>	<u>\$1.70</u>	<u>\$1.91</u>

Earnings in 2000 were reduced by 52 cents per share for special charges related to the merger and 6 cents per share for extraordinary items. For more information on these and other significant factors that had an impact on earnings, see below.

Significant Factors that Impacted 2000 Results

Special Charges Xcel Energy’s earnings for 2000 were reduced by 52 cents per share for special charges related to the merger to form Xcel Energy. During the third quarter and fourth quarter of 2000, Xcel Energy expensed pretax special charges of \$241 million, or 52 cents per share, for costs related to the merger between NSP and NCE. Of these special charges, approximately 44 cents per share were associated with the costs of merging regulated operations and 8 cents per share were associated with merger impacts on nonregulated activities. See Note 2 to the Financial Statements for more information on these charges.

Xcel Energy has completed the majority of its merger-related transition and integration activities in 2000 and expects to fully realize in 2001 and future years the operating synergies anticipated from the merger of NSP and NCE. Xcel Energy does not expect to incur any additional merger costs after 2000.

Extraordinary Items—Electric Utility Restructuring Xcel Energy’s earnings for 2000 were reduced by 6 cents per share for two extraordinary items related to the discontinuation of regulatory accounting for SPS’ generation business. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs for an extraordinary charge of approximately \$19.3 million

before tax, or \$13.7 million after tax. During the third quarter of 2000, SPS recorded an additional extraordinary charge of \$8.2 million before tax, or \$5.3 million after tax, related to the tender offer and defeasance of approximately \$295 million of first mortgage bonds. For more information, see Note 12 to the Financial Statements.

Significant Factors that Impacted 1999 Results

Conservation Incentive Recovery Earnings for 1999 were reduced by 7 cents per share due to the disallowance of 1998 conservation incentives for NSP-Minnesota. In June 1999, the Minnesota Public Utilities Commission (MPUC) denied NSP-Minnesota recovery of 1998 lost margins, load management discounts and incentives associated with state-mandated programs for electric energy conservation. Xcel Energy recorded a \$35 million charge in 1999 based on this action. NSP-Minnesota appealed the MPUC decision and in December 2000, the Minnesota Court of Appeals reversed the MPUC decision.

In January 2001, the MPUC appealed the lower court decision to the Minnesota Supreme Court. On Feb. 23, 2001, the Minnesota Supreme Court declined to hear the MPUC's appeal. NSP-Minnesota is awaiting an order from the MPUC regarding the implementation of the appeals court decision before adjusting any liabilities recorded for this matter. As of Dec. 31, 2000, NSP-Minnesota had recorded a liability of \$40 million, including carrying charges, for potential refunds to customers pending the final resolution of this matter.

In addition, based on the 1999 change in MPUC policy on conservation incentives and regulatory uncertainty, beginning in 1999 management discontinued the accrual of conservation incentives other than those approved by the MPUC.

Special Charges During 1999, Xcel Energy expensed pretax special charges of \$31 million, or 7 cents per share, stemming from asset impairments related to goodwill and marketable securities associated with nonregulated activities. See Note 2 to the Financial Statements for more information on these charges.

Nonregulated Subsidiaries

Contribution to Xcel Energy's earnings per share

	<u>2000</u>	<u>1999</u>	<u>1998</u>
NRG*	\$ 0.46	\$ 0.17	\$ 0.13
Yorkshire Power	0.13	0.13	0.12
e prime	(0.02)	(0.01)	(0.01)
Seren Innovations	(0.07)	(0.03)	(0.01)
Planergy International	(0.08)	(0.06)	(0.03)
Financing costs and preferred dividends	(0.07)	(0.03)	(0.03)
Other nonregulated	(0.01)	0.02	0.03
Total nonregulated earnings per share	<u>\$ 0.34</u>	<u>\$ 0.19</u>	<u>\$ 0.20</u>

* NRG's earnings for 2000 in this report exclude earnings of approximately 8 cents per share related to minority interests.

NRG NRG's earnings for 2000 benefited from increased electric revenues resulting from recently acquired generation assets. During 2000, NRG increased its megawatt ownership interest in generating facilities in operation by more than 4,000 megawatts. NRG's earnings for 2000 were also influenced by favorable weather conditions that increased demand for electricity in the northeast and western United States, market dynamics, strong performance from existing assets and higher market prices for electricity. As a consequence of the dynamics in the electricity markets during 2000, NRG's earnings contribution to Xcel Energy is estimated to have been approximately 8 cents per share more for the year than would occur under normal circumstances, and there can be no assurance that such dynamics will occur again. See Note 14 to the Financial Statements for a description of recent lawsuits against

NRG and other power producers and marketers involving the California electricity markets and a discussion of NRG's receivables related to the California power market.

e prime e prime's results for 2000 were reduced by special charges, recorded during the third quarter, of 2 cents per share for contractual obligations and other costs associated with post-merger changes in the strategic operations and related revaluations of e prime's energy marketing business.

Seren Innovations As expected, Seren's expansion of its broadband communications network in Minnesota and California resulted in increased losses for 2000.

Planergy International Planergy's results for 2000 were reduced by special charges of 4 cents per share for the write-offs of goodwill and project development costs. During the third quarter of 2000, Planergy and Energy Masters International (EMI), both wholly owned subsidiaries of Xcel Energy, were combined to form Planergy International. As a result of this combination, Planergy reassessed its business model and made a strategic realignment, which resulted in the write-off of \$22 million (before tax) of goodwill and project development costs.

In addition, Planergy's results for 1999 were reduced by a special charge of 4 cents per share to write off goodwill that was recorded for EMI's acquisitions of Energy Masters Corp. in 1995 and Energy Solutions International in 1997. EMI wrote off approximately \$17 million of goodwill (before tax) during the fourth quarter of 1999.

Financing Costs and Preferred Dividends Nonregulated results include interest expense and preferred dividends, which are incurred at the Xcel Energy and intermediate holding company levels and are not directly assigned to individual subsidiaries.

Other Other nonregulated results for 2000 were reduced by special charges of 2 cents per share recorded during the third quarter. These special charges include \$10 million in asset write-downs and losses resulting from various other nonregulated business ventures that are no longer being pursued.

In addition, other nonregulated results for 1999 were reduced by special charges of 3 cents per share for a valuation write-down of Xcel Energy's investment in the publicly traded common stock of CellNet Data Systems, Inc.

Income Statement Analysis

Electric Utility Margins

The following table details the changes in electric utility revenue and margin. Electric production expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel clause cost recovery mechanisms for retail customers in several states, most fluctuations in energy costs do not materially affect electric margin. However, the fuel cost recovery mechanisms in the various jurisdictions do not allow for complete recovery of all variable production expenses and, therefore, higher costs can result in an adverse margin and earnings impact.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Electric retail and firm wholesale revenue	\$5,006	\$4,671	\$4,638
Short-term wholesale revenue	674	251	346
Total electric utility revenue	5,680	4,922	4,984
Electric retail and firm wholesale fuel and purchase power . .	2,026	1,766	1,661
Short-term wholesale fuel and purchase power	542	193	312
Total electric utility fuel and purchase power	2,568	1,959	1,973
Electric retail and firm wholesale margin	2,980	2,905	2,977
Short-term wholesale margin	132	58	34
Total electric utility margin	<u>\$3,112</u>	<u>\$2,963</u>	<u>\$3,011</u>

Electric revenue increased by approximately \$758 million, or 15.4 percent, in 2000. Electric margin increased by approximately \$149 million, or 5.0 percent, in 2000. Electric margins reflect the impact of customer sharing due to the incentive cost adjustment (ICA). Weather normalized retail sales increased by 3.6 percent in 2000, increasing retail revenue by approximately \$153 million and retail margin by approximately \$88 million. More favorable temperatures during 2000 increased retail revenue by approximately \$36 million and retail margin by approximately \$22 million. These retail margin increases were partially offset by regulatory adjustments, relating to the earnings test in Texas and system reliability and availability in Colorado. Short-term wholesale revenue and margin increased due to the expansion of Xcel Energy's wholesale marketing operations and favorable market conditions.

Electric revenue decreased by approximately \$62 million, or 1.2 percent, and electric margin decreased by approximately \$48 million, or 1.6 percent, in 1999. Retail revenue and margin also decreased due to the disallowance of 1998 conservation incentives in Minnesota, which reduced retail revenue and margin by \$78 million compared with 1998. The disallowance of 1998 conservation incentives was recorded during 1999, as a result of the timing of an MPUC decision.

Despite customer growth, retail sales increased only 0.5 percent, largely due to mild weather in Colorado and Texas. In addition, retail margin was reduced by approximately \$19 million in 1999 due to higher purchased power costs in Minnesota and Wisconsin not recoverable in rates. Electric revenue decreased due to lower short-term wholesale revenue reflecting market conditions.

Gas Utility Margins

The following table details the changes in gas utility revenue and margin. The cost of gas tends to vary with changing sales requirements and the unit cost of gas purchases. However, due to purchased gas cost recovery mechanisms for retail customers, fluctuations in the cost of gas have little effect on gas margin.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Gas revenue	\$1,469	\$1,141	\$1,110
Cost of gas purchased and transported	(948)	(683)	(659)
Gas margin	<u>\$ 521</u>	<u>\$ 458</u>	<u>\$ 451</u>

Gas revenue increased by approximately \$328 million, or 28.7 percent, in 2000, primarily due to increases in the cost of natural gas, which are largely recovered through various adjustment clauses in most of the jurisdictions in which Xcel Energy operates. Gas margin increased by approximately \$63 million, or 13.8 percent, in 2000. More favorable temperatures during 2000 increased gas revenue by approximately \$82 million and gas margins by approximately \$33 million.

Gas revenue increased by approximately \$31 million, or 2.8 percent, and margin increased by approximately \$7 million, or 1.6 percent, in 1999, largely due to increased retail sales, which increased 3.2 percent compared with 1998. In addition, gas revenue and margin in 1999 increased due to higher base rates resulting from PSCo's 1998 rate case, which became effective in July 1999.

Electric and Gas Trading Margins

Xcel Energy's trading operations are conducted mainly by PSCo and e prime. Trading revenues and costs of goods sold do not include the revenue and production costs associated with energy produced from generation assets or results from NRG. The following table details the changes in electric and gas trading revenue and margin.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Trading revenue	\$ 2,056	\$ 951	\$ 135
Trading cost of goods sold	(2,017)	(946)	(134)
Trading margin	<u>\$ 39</u>	<u>\$ 5</u>	<u>\$ 1</u>

Trading revenue increased by approximately \$1.1 billion and trading margin increased by approximately \$34 million in 2000. Trading revenue increased by approximately \$816 million and trading margin increased by approximately \$4 million in 1999. The increase in trading revenue and margin is a result of the expansion of electric trading at PSCo and natural gas trading at e prime.

Nonregulated Operating Margins

The following table details the changes in nonregulated revenue and margin.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Nonregulated and other revenue	\$ 2,204	\$ 689	\$ 382
Earnings from equity investments	183	112	116
Nonregulated cost of goods sold	<u>(1,048)</u>	<u>(323)</u>	<u>(204)</u>
Nonregulated margin	<u>\$ 1,339</u>	<u>\$ 478</u>	<u>\$ 294</u>

Nonregulated and other revenue increased by approximately \$1.5 billion in 2000, largely due to NRG's acquisition of generation facilities during 2000 and the full-year impact of generating assets acquired during 1999. Earnings from equity investments increased by approximately \$71 million in 2000, primarily due to increased equity earnings from NRG projects. The increase in NRG equity earnings is primarily due to increased earnings from its investments in West Coast Power LLC and Rocky Road LLC, which benefited from warmer weather conditions and market dynamics. Nonregulated margin increased by approximately \$861 million in 2000, largely due to NRG's acquisition of generation facilities during 2000. NRG's revenue and margin also increased as a consequence of the dynamics in the electricity markets in which NRG operated in during 2000, and there can be no assurance that such dynamics will occur again. For more information, see Note 14 to the Financial Statements for a description of recent lawsuits against NRG and other power producers and marketers involving the California electricity markets and a discussion of NRG's receivables related to the California power market.

Nonregulated and other revenue increased by approximately \$307 million in 1999, largely due to NRG's acquisition of generation facilities during 1999 in the Northeast region of the United States. Earnings from equity investments decreased by approximately \$4 million, or 3.4 percent, in 1999, primarily due to lower earnings from NRG's West Coast power generating affiliate as a result of cool summer weather during 1999 compared with the summer of 1998. Nonregulated margin increased by approximately \$184 million in 1999, largely due to NRG's acquisition of generation facilities during 1999 in the Northeast region of the United States.

Non-Fuel Operating Expense and Other Items

Other utility operating and maintenance expense for 2000 increased by approximately \$71 million, or 5.3 percent, compared with 1999. The increase is largely due to the timing of outages at the Monticello and Prairie Island nuclear plants and at the Sherco coal-fired power plant, increased bad debt reserves related to wholesale and retail customers, increased transmission costs in the Southwest Power Pool, start-up costs to establish the Nuclear Management Co. and higher employee-related costs. Other utility operation and maintenance expense decreased approximately \$27 million, or 2.0 percent, in 1999, primarily due to lower benefit costs and cost-control efforts.

Nonregulated other operation and maintenance expense increased by approximately \$354 million in 2000 and \$79 million in 1999. These increases are primarily due to costs of operations acquired, increased business development activities and legal, technical and accounting expenses resulting from NRG's expanding operations. In addition, costs also increased due to Seren's expansion of its broadband communications network in Minnesota and California.

Depreciation and amortization expense increased \$113 million, or 16.6 percent, in 2000 and \$52 million, or 8.4 percent, in 1999, primarily due to acquisitions of generating facilities by NRG and increased additions to utility plant.

During 1998, NRG recorded gains of approximately \$26 million on the partial sale of NRG's interest in the Enfield project and approximately \$2 million on the sale of NRG's interest in the Mid-Continent Power facility.

Interest expense increased \$243 million, or 58.7 percent, in 2000 and \$70 million, or 20.2 percent, in 1999, primarily due to increased debt levels to finance several asset acquisitions by NRG.

Weather

Xcel Energy's earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but can also increase expenses, which may not be fully recoverable. Unseasonably mild weather reduces electric and natural gas sales. The following summarizes the estimated impact on the earnings of the utility subsidiaries of Xcel Energy due to temperature variations from historical averages.

- Weather in 2000 increased earnings by an estimated 1 cent per share.
- Weather in 1999 decreased earnings by an estimated 9 cents per share.
- Weather in 1998 decreased earnings by an estimated 4 cents per share.

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and gas service within their respective jurisdictions. In addition, Xcel Energy's nonregulated businesses are becoming a more significant factor in Xcel Energy's earnings. The historical and future trends of Xcel Energy's operating results have been and are expected to be affected by the following factors:

Competition and Industry Restructuring

The structure of the electric and natural gas utility industry continues to change rapidly. Many states are implementing retail competition with an unbundling of regulated energy services. Merger and acquisition activity over the past few years has been significant as utilities combine to capture economies of scale and/or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide non-discriminatory access to the use of their transmission systems. The transition to this competitive environment will be extremely challenging during the next few years and will most likely have significant impacts on the industry.

Some states have begun to allow retail customers to choose their electricity supplier, and many other states are considering retail access proposals. Four states in our service territory—Texas, New Mexico, Oklahoma and Michigan—currently are expected to allow customers to choose their electricity supplier in 2002. In Texas, a pilot restructuring program is scheduled to begin in June 2001, with expanded retail competition beginning January 2002. In New Mexico, retail competition is scheduled to begin in January 2002 for some customers and July for the rest. In Oklahoma, a 1997 restructuring law provides for customer choice by July 2002, pending further action from the Oklahoma Legislature. In Michigan, customer choice is expected to begin in January 2002. Following the supply and price disruptions in California, restructuring initiatives may be delayed or modified in some of the states in which we operate.

Major issues that must be addressed include mitigating market power, divestiture of generation capacity, transmission constraints, legal separation, the refinancing of securities, modification of mortgage indentures, implementation of procedures to govern affiliate transactions, investments in information technology and the pricing of unbundled services, all of which have significant financial

implications. Xcel Energy cannot predict the outcome of its restructuring proceedings at this time. The resolution of these matters may have a significant impact on the financial position, results of operations and cash flows of Xcel Energy. For more information on restructuring in Texas and New Mexico, see Note 12 to the Financial Statements.

With respect to Xcel Energy's other primary regulatory jurisdictions, the Minnesota Legislature continues to study industry restructuring issues, but has determined that further study is necessary before any action can be taken. During 1998, an electric restructuring bill was passed in Colorado that established an advisory panel to conduct an evaluation of restructuring. During 1999, this panel concluded that Colorado should not open its markets to competition. The Wisconsin Legislature has been focusing its efforts on improving electric reliability by requiring utility infrastructure improvements prior to addressing customer choice.

California Power Market

NRG operates in and sells to the wholesale power market in California. During the fourth quarter of 2000, the inability of certain California utilities to recover rising energy costs through regulated prices charged to retail customers created financial difficulties. The California utilities have appealed to state agencies and regulators for the opportunity to be reimbursed for costs incurred that are not currently recoverable through the existing rate structure. Absent such relief, some of the utilities have indicated they may be unable to continue to service their debt and/or otherwise pay obligations, or would consider discontinuing energy service to customers to avoid incurring costs that are not recoverable. Due to these circumstances, various bond rating agencies have lowered the credit rating of the California utilities to below investment grade. California state agencies and regulators, along with federal agencies such as the Federal Energy Regulatory Commission (FERC) have characterized the situation as a national emergency. Although changes may be necessary in the California utility regulatory model to address the problem in the long run, in the short term the alternatives being discussed include financial support for distressed utilities to ensure continued energy service to California customers. However, at this time it is unknown whether or when such financial support will be made available to California utilities.

As of Dec. 31, 2000, approximately 11 percent of NRG's net megawatts of operating projects and construction were located in California. NRG expects this percentage of net megawatts in California to decline to 7 percent by the end of 2001. In addition, Xcel Energy's wholesale trading operation sells power to California. See Note 14 to the Financial Statements for a description of recent lawsuits against NRG and other power producers and marketers involving the California electricity markets and a discussion of Xcel Energy and NRG's receivables related to the California power market.

Cheyenne Purchase Power Agreement

For the past 37 years, Cheyenne has purchased all energy requirements from PacifiCorp. Cheyenne's full-requirements power purchase agreement with PacifiCorp expired in December 2000. During 2000, Cheyenne issued a request for proposal and conducted negotiations with PacifiCorp and other wholesale power suppliers. During 2000, as contract details for a new agreement were being finalized, supply conditions and market prices in the western United States dramatically changed. Cheyenne was unable to execute an agreement with PacifiCorp for the prices and terms Cheyenne had been negotiating. Additionally, PacifiCorp failed to provide the FERC and Cheyenne a 60-day notice to terminate service, as required by the Federal Power Act. Cheyenne filed a complaint with the FERC, requesting that PacifiCorp continue providing service under the existing tariff through the 60-day notice period. On Feb. 7, 2001, the FERC issued an order requiring PacifiCorp to provide service under the terms of the old contract through Feb. 24, 2001.

Cheyenne has begun implementing the changes required to transition from a full-requirements customer to an operating utility as the best means of providing energy supply. In February 2001, PSCo filed an agreement with the FERC to provide a portion of Cheyenne's service. Cheyenne has also

entered into agreements with other producers to meet both short term and long term energy supply needs and continues to negotiate with suppliers to meet its load requirements for the summer of 2001.

Total purchased power costs are projected to increase approximately \$80 million in 2001 with costs anticipated to fall each year thereafter. Purchased power and natural gas costs are recoverable in Wyoming. Cheyenne is required to file applications with the Wyoming Public Service Commission (WPSC) for approval of adjustment mechanisms in advance of the proposed effective date. Cheyenne expects to make its request for an electric cost adjustment increase in March 2001.

The filing is expected to mitigate customer impacts through a pricing plan that would defer certain first-year costs. In addition, Cheyenne expects to make other filings to create new options for customers to move load to off-peak hours and to provide additional conservation opportunities. While the precise outcome of this matter cannot be predicted, management believes that it will not have a material adverse effect on its results of operations or financial conditions.

Regulation

Following the merger of NSP and NCE, Xcel Energy became a registered holding company under the PUHCA. As a result, Xcel Energy, its utility subsidiaries and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. Xcel Energy believes that it has adequate authority (including financing authority) under existing SEC orders and regulations for it and its subsidiaries to conduct their businesses as proposed during 2001 and will seek additional authorization when necessary.

The electric and natural gas rates charged to customers of Xcel Energy's utility subsidiaries are approved by the FERC and the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Because comprehensive rate changes are requested infrequently in some states, changes in operating costs can affect Xcel Energy's financial results. 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.

Except for Wisconsin electric operations, most of the retail rate schedules for Xcel Energy's utility subsidiaries provide for periodic cost-of-energy and resource adjustments to billings and revenues for changes in the cost of fuel for electric generation, purchased energy, purchased natural gas and, in Minnesota and Colorado, conservation and energy management program costs. In Minnesota, changes in electric capacity costs are not recovered through the fuel clause. For Wisconsin electric operations, where cost-of-energy adjustment clauses are not used, the biennial retail rate review process and an interim fuel cost hearing process provide the opportunity for rate recovery of changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In Colorado, PSCo has an ICA, which allows for an equal sharing among customers and shareholders of certain fuel and energy costs and certain gains and losses on trading margins.

Regulated public utilities are allowed to record as assets certain costs that would be expensed by nonregulated enterprises and to record as liabilities certain gains that would be recognized as income by nonregulated enterprises. If restructuring or other changes in the regulatory environment occur, Xcel Energy may no longer be eligible to apply this accounting treatment and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material, adverse affect on Xcel Energy's results of operations in the period the write-off is recorded. As discussed in Note 12 to the Financial Statements, SPS' generation business no longer follows SFAS 71.

At Dec. 31, 2000, Xcel Energy reported on its balance sheet regulatory assets of approximately \$365 million and regulatory liabilities of approximately \$204 million that would be recognized in the income statement in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. Xcel Energy currently does not expect to write off any stranded costs unless market price levels change or cost levels increase above market price levels. See Notes 1 and 16 to the Financial Statements for further discussion of regulatory deferrals.

As of Dec. 31, 2000, SPS had approximately \$104 million of unrecovered energy costs, largely due to increases in the cost of natural gas for generating electricity. These costs would typically be recovered through SPS' filings with state commissions. As part of restructuring in Texas, the fuel cost recovery mechanism will not be in effect after 2001. Consistent with past practices, SPS has requested recovery of these costs. Management is confident that these unrecovered energy costs were prudent and will ultimately be recovered from customers.

Merger Rate Agreements

As part of the merger approval process, Xcel Energy agreed to reduce its rates in several jurisdictions. The discussion below summarizes the rate reductions in Colorado, Minnesota, Texas and New Mexico.

As part of the merger approval process in Colorado, PSCO agreed to:

- Reduce its retail electric rates by \$11 million annually through June 2002;
- File a combined electric and natural gas rate case in 2002, with new rates effective January 2003;
- Cap merger costs associated with the electric operations at \$30 million and amortize the merger costs for rate-making purposes through 2003; and
- Continue the Performance Based Regulatory Plan (PBRP) and the Quality Service Plan (QSP) currently in effect through 2006 with modifications to cap electric earnings at a 10.5-percent return on equity for 2002, no earnings sharing in 2003 since new base rates would have recently been established and increase potential refunds if quality standards are not met, including a QSP for natural gas operations.

As part of the merger approval process in Minnesota, NSP-Minnesota agreed to:

- Reduce its Minnesota electric rates by \$10 million annually for 2001-2005;
- Not increase its electric rates through 2005, except under limited circumstances; and
- Not seek the recovery of certain merger costs from customers and meet various quality standards.

As part of the merger approval process in Texas, SPS agreed to:

- Guarantee annual merger savings credits of approximately \$4.8 million and amortize merger costs through 2005;
- Retain the current fuel-recovery mechanism to pass along fuel cost savings to retail customers through 2001; and
- Comply with various service quality and reliability standards covering service installations and upgrades, light replacements, customer service call centers and electric service reliability.

As part of the merger approval process in New Mexico, SPS agreed to:

- Guarantee annual merger savings credits of approximately \$780,000 and amortize merger costs beginning July 2000 through December 2004;
- Share net non-fuel operating and maintenance savings equally among retail customers and shareholders;

- Retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and
- Not pass along any negative rate impacts of the NCE/NSP merger.

PSCo Performance-Based Regulatory Plan

The Colorado Public Utility Commission (CPUC) established an electric PBRP under which PSCo operates. The major components of this regulatory plan include:

- An annual electric earnings test with the sharing of earnings in excess of an 11-percent return on equity for 1997-2001;
- An annual electric earnings test with the sharing between customers and shareholders of earnings in excess of a 10.50-percent return on equity for 2002;
- No earnings sharing for 2003;
- An annual electric earnings test with the sharing of earnings in excess of the return on equity set in the 2002 rate case for 2004-2006;
- A Quality Service Plan (QSP) that provides for refunds to customers if PSCo does not achieve certain performance measures relating to electric reliability and customer service; and
- An ICA that provides for the sharing of energy costs and savings relative to an annual target cost per delivered kilowatt-hour.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the earnings test. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually. PSCo has recorded an estimated customer refund obligation for 2000 of approximately \$12.2 million. PSCo has also recorded an estimated customer refund obligation for 2000 under the QSP electric reliability performance measure of approximately \$6.7 million. In November 2000, the CPUC ruled on the unresolved issues related to the 1998 earnings test. PSCo filed to reduce customer rates by \$5.1 million effective January 2001, in compliance with the CPUC decision for both the 1998 and 1999 earnings test years. The procedural schedule for the 1999 earnings test has been established, with hearings set for April 2001.

SPS Earnings Test

In Texas, SPS operates under an earnings test in which excess earnings are returned to the customer. In May 2000, SPS filed its 1999 Earnings Report with the Public Utilities Commission of Texas (PUCT), indicating no excess earnings. In September 2000, the PUCT staff and the Office of Public Utility Counsel (OPUC) filed a Notice of Disagreement with the PUCT, indicating adjustments to SPS' calculations, which would result in excess earnings. During 2000, SPS recorded an estimated obligation of approximately \$11.4 million for 1999 and 2000. In February 2001, the PUCT ruled on the disputed issues. These adjustments will not materially affect the estimated obligation previously booked.

Environmental Matters

Xcel Energy incurs several types of environmental costs, including nuclear plant decommissioning; storage and ultimate disposal of spent nuclear fuel; disposal of hazardous materials and wastes; remediation of contaminated sites; and monitoring of discharges into the environment. Because of greater environmental awareness and increasingly stringent regulation, Xcel Energy has experienced increasing environmental costs. This trend has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance. In addition, NRG's acquisition of existing generation facilities will tend to increase nonutility costs for environmental compliance.

In addition to nuclear decommissioning and spent nuclear fuel disposal expenses, costs charged to Xcel Energy's operating expenses for environmental monitoring and disposal of hazardous materials and wastes were approximately:

- \$64 million in 2000
- \$55 million in 1999
- \$56 million in 1998

Xcel Energy expects to spend approximately \$72 million per year for 2001-2005. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown.

Capital expenditures on environmental improvements at its utility facilities, which include the costs of constructing spent nuclear fuel storage casks, were approximately:

- \$57 million in 2000
- \$126 million in 1999
- \$101 million in 1998

Xcel Energy expects to incur approximately \$132 million in capital expenditures for compliance with environmental regulations in 2001 and approximately \$297 million for 2001-2005. See Notes 14 and 15 to the Financial Statements for further discussion of Xcel Energy's environmental contingencies.

Impact of Nonregulated Investments

Xcel Energy's earnings from nonregulated operations have increased significantly due to acquisitions. Xcel Energy expects to continue investing in nonregulated projects, including domestic and international power production projects through NRG, international projects through Xcel Energy International, natural gas trading and marketing through e prime, construction projects through Utility Engineering and broadband communications systems through Xcel Communications. Xcel Energy's nonregulated businesses may carry a higher level of risk than its traditional utility businesses due to a number of factors, including:

- Competition, operating risks, dependence on certain suppliers and customers, and domestic and foreign environmental and energy regulations;
- Partnership and government actions and foreign government, political, economic and currency risks; and
- Development risks, including uncertainties prior to final legal closing.

Some of Xcel Energy's nonregulated subsidiaries have project investments (as listed in Note 11 to the Financial Statements) consisting of minority interests, which may limit the financial risk, but may also limit the ability to control the development or operation of the projects. In addition, significant expenses may be incurred for projects pursued by Xcel Energy's subsidiaries that do not materialize. The aggregate effect of these factors creates the potential for volatility in the nonregulated component of Xcel Energy's earnings. Accordingly, the historical operating results of Xcel Energy's nonregulated businesses may not necessarily be indicative of future operating results.

Subsequent Event In late February 2001, Xcel Energy reached an agreement in principle to sell at book value all of its investment in Yorkshire Power except for an interest of approximately 5 percent. Xcel Energy is retaining this interest to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Following completion of the transaction, proceeds of the sale will be used by Xcel Energy to pay down short-term debt and eliminate an equity issuance planned for the second half of 2001.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders.

Accounting Changes

The Financial Accounting Standards Board (FASB) has proposed new accounting standards that would require the full accrual of nuclear plant decommissioning and certain other site exit obligations. Material adjustments to Xcel Energy's balance sheet would occur upon implementation of the FASB's proposal, which would be no earlier than 2002. 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 15 to the Financial Statements.

In June 1998, the FASB issued Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment to FASB Statement No. 133."

SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met or specific exclusions are applicable. Special accounting for qualifying hedges allows a derivative instrument's gains and losses to offset related results on the hedged item in the income statement, to the extent effective, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

SFAS 133 will apply to Xcel Energy's accounting for commodity futures and options contracts, index or fixed price swaps and basis swaps used to hedge price volatility in the markets. SFAS 133 will also apply to Xcel Energy's accounting for interest rate swaps used to hedge exposure to changes in interest rates and foreign currency hedges. Xcel Energy may apply hedge accounting to account for these derivative instruments, provided they meet specific hedge accounting criteria.

Xcel Energy plans to adopt SFAS 133 in 2001, as required. Xcel Energy expects the following:

- An initial gain or loss recorded in the first quarter of 2001 related to the cumulative effect of applying the new accounting method to periods prior to 2001, which will be reported as a separate after-tax gain or loss based on market pricing levels in effect at Jan. 1, 2001;
- Increased volatility in future earnings due to the impact of market fluctuations on derivative instruments used by Xcel Energy and its subsidiaries; and
- Potential changes in Xcel Energy's business practices.

Xcel Energy has completed its implementation of SFAS 133 in January 2001. Based on market prices as of Dec. 31, 2000, there was no material impact from the cumulative effect reported in earnings and a net loss of approximately \$42 million reported in other comprehensive income (equity) due to implementation of SFAS 133.

Derivatives, Risk Management and Market Risk

Xcel Energy is exposed to market and credit risks in its generation, retail distribution and energy trading operations. To minimize the risk of market price and volume fluctuations, Xcel Energy enters into financial derivative instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories of its natural gas, distillate fuel oil, electricity and coal business, and emission allowances. The primary objective of Xcel Energy's trading operations is to maximize asset

value, while minimizing the related exposure to changes in commodity prices and counterparty default. These operations include wholesale power trading and natural gas marketing and trading activities.

Xcel Energy monitors its exposure to fluctuations in interest rates and foreign exchange and may execute swaps, forward exchange contracts or other financial derivative instruments to manage these exposures. Xcel Energy manages all of its market risks through various policies and procedures that allow for the use of various derivative instruments in the energy and financial markets.

Commodity Price Risk Xcel Energy has continued to develop and expand its gas and power marketing and trading activities, and management expects to continue the growth of these activities during 2001. As a result, Xcel Energy's exposure to changes in commodity prices may increase and earnings may experience volatility. To manage exposure to price volatility in the natural gas and electricity markets, Xcel Energy uses a variety of energy contracts, both financial and physical. These contracts consist mainly of commodity forward contracts and options, index or fixed price swaps and basis swaps.

Xcel Energy measures its open exposure to commodity price changes using the Value-at-Risk (VaR) methodology. VaR expresses the potential loss in fair value of all open forward contract and option positions over a particular period of time, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR, which assumes that all price returns/profitability are normally and independently distributed. The model employs a 95 percent confidence interval level based on historical price movement, normal price distribution and a holding period of 21 days.

NRG has developed a 12-month rolling VaR based on generation assets, load obligations and bilateral physical and financial transactions. This model encompasses the following generating regions: Entergy, NEPOOL and NYPP. NRG is in the process of expanding the model into other geographical areas. The VaR for NRG reflects its merchant strategy and calculated estimated earnings variability over the next three days based on a confidence factor of 95 percent. The volatility estimate is based on a lognormal calculation of the latest 30-day closes for forward markets where NRG has an exposure.

As of Dec. 31, 2000, the calculated VaRs were:

	<u>Year Ended Dec. 31, 2000</u>	<u>Average</u>	<u>High</u>	<u>Low</u>
	(Millions of dollars)			
OPERATIONS				
Regulated trading	4.62	1.42	7.23	0.08
Regulated wholesale	1.40	0.73	4.70	0.01
e prime retail	0.69	0.70	1.94	0.12
e prime wholesale	0.03	0.35	1.37	0.02
NRG	116.0	80.0	125.0	50.0

Xcel Energy does not use VaR to measure the commodity risk inherent in its regulated generation and retail sales operations. In its major regulatory jurisdictions, Xcel Energy has limited exposure to commodity risk due to fuel-cost recovery adjustment mechanisms. In Minnesota, fuel cost increases may be passed along in full to retail consumers.

In Colorado, a sharing mechanism between shareholders and customers exists that utilizes an established benchmark per unit cost for energy. Consequently, changes in any eligible costs collected under this benchmark approach have a resultant market risk. The impact of eligible production and fuel cost volatility on Colorado jurisdiction retail business shows that as of Dec. 31, 2000, a 15-percent increase in eligible production and fuel costs would result in a loss in income from these contracts of approximately \$18 million. Conversely, a 15-percent decrease in eligible production and fuel costs would result in a positive income gain from these contracts of approximately \$39 million. This analysis assumes that there were no changes in energy consumption, customer growth, operations, energy dispatch, regulatory guidelines or market conditions. This analysis is solely focused on the change in fuel eligible production and fuel costs and the resultant market risk due to the ICA mechanism in the

state of Colorado. The market risk caused by change in eligible production and fuel costs, under the ICA mechanism, is affected by margins earned on certain trading activities. Generally, these margins serve to mitigate the impact of market risk on Xcel Energy and the customer.

Interest Rate Risk Xcel Energy and its subsidiaries have both long-term and short-term debt instruments that subject Xcel Energy and certain of its subsidiaries to the risk of loss associated with movements in market interest rates. This risk is limited for Xcel Energy's regulated companies, primarily due to cost-based rate regulation. In the future, management anticipates utilizing financial instruments to manage its exposure to changes in interest rates. These instruments may include interest rate swaps, caps, collars, exchange-traded futures contracts and put or call options on U.S. Treasury securities.

At Dec. 31, 2000, a 100-basis point change in the benchmark rate on Xcel Energy's variable debt would impact net income by approximately \$15.8 million. As a result of interest rate swaps, which converted floating-rate debt into fixed-rate debt, NRG did not have material interest rate exposure as of Dec. 31, 2000.

Currency Exchange Risk Xcel Energy's investment in Yorkshire Power, a foreign currency-denominated joint venture, and various NRG foreign projects also expose Xcel Energy to currency translation rate risk. NRG has an investment in the Kladno project located in the Czech Republic. SFAS No. 52—"Foreign Currency Translation" requires foreign currency gains and losses to flow through the income statement if settlement of an obligation is in a currency other than the local currency of the entity. A portion of the Kladno project debt is in non-local currency (U.S. dollars and German deutsche marks). As of Dec. 31, 2000, if the value of the Czech koruna decreased by 10 percent in relation to the U.S. dollar and the German deutsche mark, NRG would have recorded a \$3.6 million loss (after tax) on the currency transaction adjustment. If the value of the Czech koruna increased by 10 percent, NRG would have recorded a \$3.6 million gain (after tax) on the currency transaction adjustment.

At Dec. 31, 2000, Xcel Energy's exposure to changes in foreign currency exchange rates through its investment in Yorkshire Power is not material to its consolidated financial position, results of operations or cash flows.

Credit Risk In addition to the risks discussed previously, Xcel Energy and its subsidiaries are exposed to credit risk in its risk management activities. Credit risk relates to the risk of loss resulting from the nonperformance by a counterparty of its contractual obligations. As Xcel Energy continues to expand its natural gas and power marketing and trading activities, its exposure to credit risk and counterparty default may increase. Xcel Energy and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

Xcel Energy and its subsidiaries conduct standard credit reviews for all of its counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees and standardized master netting agreements that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. See Note 14 to the Financial Statements for a discussion of NRG's receivable related to the California power market.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Net cash provided by operating activities	\$1,408	\$1,325	\$1,362

Cash provided by operating activities increased during 2000, compared with 1999, primarily due to improvements in working capital and additional depreciation, a non-cash reduction to earnings. Cash

provided by operating activities decreased slightly during 1999, compared with 1998, primarily due to a decrease in working capital due to timing of cash flows.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Net cash used in investing activities	\$(3,347)	\$(2,953)	\$(1,221)

Cash used in investing activities increased during 2000, compared with 1999, primarily due to acquisitions of existing generating facilities by NRG. Cash used in investing activities increased during 1999, compared with 1998, primarily due to acquisitions of existing generating facilities by NRG and increased levels of utility capital expenditures.

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Net cash provided by (used in) financing activities	\$2,016	\$1,668	\$(169)

Cash provided by financing activities increased during 2000, compared with 1999, primarily due to the issuance of debt to finance NRG asset acquisitions in 2000. Cash provided by financing activities increased during 1999, compared with 1998, primarily due to the issuance of debt to finance NRG asset acquisitions in 1999.

Prospective Capital Requirements

The estimated cost, as of Dec. 31, 2000, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements for the years 2001, 2002 and 2003 are shown in the table below.

	<u>2001</u>	<u>2002</u>	<u>2003</u>
	(Millions of dollars)		
Electric utility	\$ 931	\$ 979	\$ 962
Gas utility	162	209	146
Common utility	114	107	38
Total utility	<u>1,207</u>	<u>1,295</u>	<u>1,146</u>
NRG	3,138	1,341	1,517
Other nonregulated	91	53	12
Total capital expenditures	<u>4,436</u>	<u>2,689</u>	<u>2,675</u>
Sinking funds and debt maturities	605	311	663
Total capital requirements	<u>\$5,041</u>	<u>\$3,000</u>	<u>\$3,338</u>

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission control equipment may impact actual capital requirements. For more information, see Notes 12 and 14 to the Financial Statements.

Xcel Energy's subsidiaries expect to invest significant amounts in nonregulated projects in the future. Financing requirements for nonregulated project investments will vary depending on the success, timing and level of involvement in projects currently under consideration. These investments could cause significant changes to the capital requirement estimates for nonregulated projects and property. Long-term financing may be required for such investments.

NRG expects to invest approximately \$3.1 billion in 2001 for nonregulated projects and property, which include acquisitions and project investments. NRG's future capital requirements may vary

significantly. For 2001, NRG's capital requirements reflect expected acquisitions of existing generation facilities, including the Conectiv fossil assets, North Valmy, LS Power, Clark gas-fired assets, Reid Gardner coal-fired assets and the Bridgeport and New Haven Harbor coal-fired facilities.

Common Stock Dividend

Xcel Energy initially adopted a dividend of \$1.50 per share on an annual basis for 2000. Future dividend levels will be dependent upon Xcel Energy's results of operations, financial position, cash flows and other factors, and will be evaluated by the Xcel Energy board of directors.

Capital Sources

Xcel Energy expects to meet future financing requirements by periodically issuing long-term debt, short-term debt, common stock and preferred securities to maintain desired capitalization ratios. Over the long term, Xcel Energy's equity investments in and acquisitions of nonregulated projects are expected to be financed at the nonregulated subsidiary level from internally generated funds or the issuance of subsidiary debt. Financing requirements for the nonregulated projects, in excess of equity contributions from partners, are expected to be fulfilled through project or subsidiary debt and in the case of NRG, additional common equity or preferred offerings to the public. The financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the construction programs and other capital requirements of Xcel Energy and its subsidiaries.

NRG Initial Public Offering (IPO) During the second quarter of 2000, NRG completed an IPO of approximately 32.4 million shares priced at \$15 per share. Upon completion of the IPO, Xcel Energy owns approximately 147.6 million Class A shares of NRG common stock, or 82 percent of NRG's outstanding shares. Management has concluded that this offering of NRG stock did not affect Xcel Energy's ability to use the pooling-of-interests method of accounting for the merger of NSP and NCE. The offering's net proceeds of approximately \$454 million were used exclusively by NRG for general corporate purposes, including funding a portion of NRG's project investments and other capital requirements for 2000. No proceeds of this offering were received by Xcel Energy. A portion of the proceeds was accounted for as a gain on the sale of 18 percent of Xcel Energy's ownership in NRG. This gain of \$216 million was not recorded in earnings, but is consistent with Xcel Energy's accounting policy, which was recorded as an increase in the common stock premium component of stockholders' equity.

During 2000, Xcel Energy's board of directors authorized NRG to raise up to \$600 million of equity through a follow-on offering. NRG expects to issue up to 18.4 million shares of common stock in March 2001. If all 18.4 million shares of common stock are issued, Xcel Energy's ownership interest in NRG will decline to approximately 75 percent. In addition, NRG expects to issue 8 million equity units in March 2001. Each equity unit comprises a debenture and an obligation to acquire one share of NRG common stock no later than 2004. The ultimate issuance of common stock, number of shares issued and amount of capital raised will be dependent upon market conditions. No proceeds of any such offering would be received by Xcel Energy.

If Xcel Energy's ownership interest in NRG declines to less than 80 percent, then NRG will no longer be included in Xcel Energy's federal consolidated income tax return. We do not expect this to have a material impact on our earnings.

NRG Revolving Credit Facility During the first quarter of 2001, NRG entered into a \$2.5 billion revolving funding program, which will be used to finance a significant portion of NRG's U.S. acquisitions and development projects over the next five years. This revolving credit facility will allow NRG to procure temporary funding for both the non-recourse debt portion as well as equity contributions for new projects through an expedient and simplified review and approval process. NRG is permitted under the revolver to repay borrowed funds, thus making them available to be borrowed again. NRG plans to do that by refinancing projects in the long-term capital or bank markets when construction projects reach commercial operation or the market conditions are favorable. Any unutilized borrowing capacity may be redeployed for future projects.

Registration Statements Xcel Energy's Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2000, Xcel Energy had approximately 341 million shares of common stock outstanding. In addition, Xcel Energy's Articles of Incorporation authorize the issuance of 7 million shares of \$100 par value preferred stock. On Dec. 31, 2000, Xcel Energy had approximately 1 million shares of preferred stock outstanding.

During 2000, Xcel Energy filed a \$1 billion universal debt shelf registration with the SEC. During the fourth quarter of 2000, Xcel Energy issued \$600 million of unsecured debt under this shelf registration.

PSCo has an effective shelf registration statement with the SEC under which \$300 million of senior debt securities are available for issuance.

During 2000, NRG filed a shelf registration with the SEC. Based on this registration, NRG can issue up to \$1.65 billion of an indeterminate amount of debt securities, preferred stock, common stock, depository shares, warrants and convertible securities. This registration includes \$150 million of securities that are being carried forward from a previous NRG shelf registration.

Short-Term Borrowing Arrangements For information on Xcel Energy's short-term borrowing arrangements, see Note 3 to the Financial Statements.

Shareholder Rights Plan Xcel Energy recently adopted a shareholder rights plan. The plan is subject to SEC approval. For more information, see Note 9 to the Financial Statements.

ITEM 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

See Management's Discussion and Analysis under Item 7, incorporated by reference.

ITEM 8—FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See Item 14(a)-1 in Part IV for index of financial statements included herein.

See Note 19 of Notes to Financial Statements for summarized quarterly financial data.

REPORTS OF MANAGEMENT AND INDEPENDENT PUBLIC ACCOUNTANTS

REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of Xcel Energy'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 Xcel Energy. 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 in the United States. During the audit, they obtained an understanding of Xcel Energy's internal control structure, and performed tests and other procedures to the extent required by generally accepted auditing standards in the United States.

The board of directors pursues its oversight role with respect to Xcel Energy's financial statements through the Audit Committee, which is comprised solely of nonmanagement directors. The committee meets periodically with the independent public accountants, internal auditors and management to ensure 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.

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

/s/ WAYNE H. BRUNETTI

Wayne H. Brunetti
President and Chief Executive
Officer

/s/ EDWARD J. MCINTYRE

Edward J. McIntyre
Vice President and Chief
Financial Officer

Xcel Energy Inc.
Minneapolis, Minnesota
March 2, 2001

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries as of Dec. 31, 2000 and 1999, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended Dec. 31, 2000. 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 audits. We did not audit the consolidated financial statements of NRG Energy, Inc. for the year ended Dec. 31, 2000, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets and revenues of 28 percent and 17 percent, respectively, of the related consolidated totals. We also did not audit the consolidated financial statements of Northern States Power Co., for the years ended Dec. 31, 1999 or 1998, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets of 54 percent in 1999 and total revenues of 44 percent and 46 percent in 1999 and 1998, respectively, of the related consolidated totals. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. and Northern States Power Co. for the periods described above, is based solely on the reports of the other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the reports of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and its subsidiaries as of Dec. 31, 2000 and 1999, and the results of their operations and their cash flows for each of the years in the three-year period ended Dec. 31, 2000, in conformity with accounting principles generally accepted in the United States.

/s/ ARTHUR ANDERSEN LLP

Arthur Andersen LLP

Minneapolis, Minnesota

March 2, 2001

REPORTS OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders of NRG Energy, Inc.:

In our opinion, the consolidated balance sheet and the related consolidated statements of income, of stockholders' equity and cash flows present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries (not presented separately herein) at Dec. 31, 2000, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. 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 auditing standards generally accepted in the United States of America, 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 our opinion.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 2, 2001

To the Shareholders of Xcel Energy Inc.:

In our opinion, the consolidated balance sheets and statements of capitalization as of Dec. 31, 1999, and the related consolidated statements of income, of common stockholders' equity and of cash flows for the years ended Dec. 31, 1999 and 1998, of Northern States Power Co. and its subsidiaries (not presented separately herein) present fairly, in all material respects, the results of operations and cash flows of Northern States Power Co. and its subsidiaries for the years ended Dec. 31, 1999 and 1998, and its financial position at Dec. 31, 1998, in conformity with accounting principles generally accepted in the United States. 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 audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States, 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 audits provide a reasonable basis for the opinion expressed above.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

Jan. 31, 2000, except as to Note 2,

which is as of Feb. 22, 2000

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31		
	2000	1999	1998
	(Thousands of dollars, except per share data)		
OPERATING REVENUES:			
Electric utility	\$ 5,679,925	\$ 4,921,612	\$ 4,984,232
Gas utility	1,468,880	1,141,429	1,110,004
Electric and gas trading	2,056,399	951,490	135,471
Nonregulated and other	2,203,878	688,888	382,603
Equity earnings from investments in affiliates	182,714	112,124	115,985
Total revenue	11,591,796	7,815,543	6,728,295
OPERATING EXPENSES:			
Electric fuel and purchased power—utility	2,568,150	1,958,912	1,973,043
Cost of gas sold and transported—utility	948,145	683,455	659,493
Electric and gas trading costs	2,016,927	946,139	133,508
Cost of sales—nonregulated and other	1,047,617	323,262	203,958
Other operating and maintenance expenses—utility	1,398,708	1,327,797	1,354,980
Other operating and maintenance expenses—nonregulated	656,260	302,201	223,374
Depreciation and amortization	792,395	679,851	627,438
Taxes (other than income taxes)	351,412	360,916	356,045
Special charges (see Note 2)	241,042	31,114	790
Total operating expenses	10,020,656	6,613,647	5,532,629
Operating income	1,571,140	1,201,896	1,195,666
OTHER INCOME (EXPENSE):			
Minority interest	(40,489)	(2,773)	
Gain on sale of nonregulated projects			29,951
Interest income and other—net	16,107	4,560	22,390
Total other income (expense)	(24,382)	1,787	52,341
INTEREST CHARGES AND FINANCING COSTS:			
Interest charges—net of amounts capitalized	657,305	414,277	344,643
Distributions on redeemable preferred securities of subsidiary trusts	38,800	38,800	33,311
Dividend requirements and redemption premium on preferred stock of subsidiaries			5,332
Total interest and financing costs	696,105	453,077	383,286
Income before income taxes and extraordinary items	850,653	750,606	864,721
Income taxes	304,865	179,673	240,391
Income before extraordinary items	545,788	570,933	624,330
Extraordinary items, net of income taxes of \$8,549 (see Note 12)	(18,960)		
Net income	526,828	570,933	624,330
Dividend requirements and redemption premiums on preferred stock	4,241	5,292	5,548
Earnings available for common shareholders	\$ 522,587	\$ 565,641	\$ 618,782
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
Basic	337,832	331,943	323,883
Diluted	338,111	332,054	324,355
EARNINGS PER SHARE—BASIC AND DILUTED:			
Income before extraordinary items	\$ 1.60	\$ 1.70	\$ 1.91
Extraordinary items (see Note 12)	(0.06)		
Earnings per share	\$ 1.54	\$ 1.70	\$ 1.91

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31		
	2000	1999	1998
	(Thousands of dollars)		
OPERATING ACTIVITIES:			
Net income	\$ 526,828	\$ 570,933	\$ 624,330
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	828,780	718,323	659,226
Nuclear fuel amortization	44,591	50,056	43,816
Deferred income taxes	62,716	18,161	5,231
Amortization of investment tax credits	(15,295)	(14,800)	(14,654)
Allowance for equity funds used during construction	3,848	(1,130)	(8,509)
Undistributed equity in earnings of unconsolidated affiliates	(87,019)	(67,926)	(56,952)
Write-down of investments in projects			26,740
Gain on sale of nonregulated projects		(37,194)	(26,200)
Special charges—noncash	96,113	31,114	
Conservation incentive adjustments—noncash	19,248	71,348	
Extraordinary items (see Note 12)	18,960		
Change in accounts receivable	(443,347)	(113,521)	8,373
Change in inventories	21,933	(44,183)	(12,550)
Change in other current assets	(484,288)	(164,995)	22,263
Change in accounts payable	713,069	214,791	2,105
Change in other current liabilities	129,557	81,056	60,618
Change in other assets and liabilities	(27,969)	13,396	27,767
Net cash provided by operating activities	1,407,725	1,325,429	1,361,604
INVESTING ACTIVITIES:			
Nonregulated capital expenditures and asset acquisitions	(2,196,168)	(1,620,462)	(58,748)
Utility capital/construction expenditures	(984,935)	(1,178,663)	(1,014,710)
Allowance for equity funds used during construction	(3,848)	1,130	8,509
Investments in external decommissioning fund	(48,967)	(39,183)	(41,360)
Equity investments, loans and deposits for nonregulated projects	(93,366)	(240,282)	(234,214)
Collection of loans made to nonregulated projects	17,039	81,440	109,530
Other investments—net	(36,749)	43,136	10,011
Net cash used in investing activities	(3,346,994)	(2,952,884)	(1,220,982)
FINANCING ACTIVITIES:			
Short-term borrowings—net	42,386	1,315,027	(84,471)
Proceeds from issuance of long-term debt	3,565,227	1,215,312	641,123
Repayment of long-term debt, including reacquisition premiums	(1,667,315)	(465,045)	(394,506)
Proceeds from issuance of preferred securities			187,700
Proceeds from issuance of common stock	116,678	95,317	234,171
Proceeds from the public offering of NRG stock	453,705		
Redemption of preferred stock, including reacquisition premiums	(20)		(276,824)
Dividends paid	(494,992)	(492,456)	(476,172)
Net cash provided by (used in) financing activities	2,015,669	1,668,155	(168,979)
Effect of exchange rate changes on cash	360		
Net increase (decrease) in cash and cash equivalents	76,760	40,700	(28,357)
Cash and cash equivalents at beginning of year	139,731	99,031	127,388
Cash and cash equivalents at end of year	\$ 216,491	\$ 139,731	\$ 99,031
Supplemental disclosure of cash flow information			
Cash paid for interest (net of amount capitalized)	\$ 610,584	\$ 458,897	\$ 397,680
Cash paid for income taxes (net of refunds received)	\$ 216,087	\$ 193,448	\$ 209,781

See Notes to Consolidated Financial Statements

CONSOLIDATED BALANCE SHEETS

	December 31	
	2000	1999
	(Thousands of dollars)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 216,491	\$ 139,731
Accounts receivable—net of allowance for bad debts: \$41,350 and \$13,043, respectively	1,289,724	800,066
Accrued unbilled revenues	683,266	410,798
Materials and supplies inventories	286,453	306,524
Fuel and gas inventories	194,380	152,874
Recoverable purchased gas and electric energy costs	283,167	54,916
Prepayments and other	174,593	196,035
Total current assets	3,128,074	2,060,944
PROPERTY, PLANT AND EQUIPMENT, AT COST:		
Electric utility plant	15,304,407	14,807,684
Gas utility plant	2,376,868	2,266,516
Nonregulated property and other	5,641,968	3,242,410
Construction work in progress	622,494	533,046
Total property, plant and equipment	23,945,737	20,849,656
Less: accumulated depreciation	(8,759,322)	(8,153,434)
Nuclear fuel—net of accumulated amortization: \$967,927 and \$923,336, respectively	86,499	102,727
Net property, plant and equipment	15,272,914	12,798,949
OTHER ASSETS:		
Investments in unconsolidated affiliates	1,459,410	1,439,002
Nuclear decommissioning fund and other investments	732,908	651,086
Regulatory assets	524,261	566,727
Other	651,276	553,650
Total other assets	3,367,855	3,210,465
Total assets	\$21,768,843	\$18,070,358
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Current portion of long-term debt	\$ 603,611	\$ 431,049
Short-term debt	1,475,072	1,432,686
Accounts payable	1,608,989	793,139
Taxes accrued	236,837	260,676
Dividends payable	128,983	127,568
Other	618,316	438,101
Total current liabilities	4,671,808	3,483,219
DEFERRED CREDITS AND OTHER LIABILITIES:		
Deferred income taxes	1,794,193	1,779,046
Deferred investment tax credits	198,108	214,008
Regulatory liabilities	494,566	442,204
Benefit obligations and other	588,288	420,140
Total deferred credits and other liabilities	3,075,155	2,855,398
Minority interest in subsidiaries	277,335	14,696
CAPITALIZATION (SEE STATEMENTS OF CAPITALIZATION):		
Long-term debt	7,583,441	5,827,485
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 6)	494,000	494,000
Preferred stockholders' equity	105,320	105,340
Common stockholders' equity	5,561,784	5,290,220
COMMITMENTS AND CONTINGENCIES (SEE NOTE 14)		
Total liabilities and equity	\$21,768,843	\$18,070,358

See Notes to Consolidated Financial Statements

**CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
AND OTHER COMPREHENSIVE INCOME**

	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Accumulated Other Comprehensive Income	Total Stockholders' Equity
(Thousands of dollars)						
BALANCE AT DEC. 31, 1997	\$802,245	\$1,972,223	\$2,023,925	\$(10,533)	\$ (58,745)	\$4,729,115
Net income			624,330			624,330
Unrealized loss from marketable securities, net of tax of \$4,417					(6,416)	(6,416)
Currency translation adjustments					(16,089)	(16,089)
Other comprehensive income for 1998						601,825
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(5,548)			(5,548)
Common stock			(475,399)			(475,399)
Issuances of common stock—net	23,150	223,985				247,135
Pooling of interests business combinations			6,065			6,065
Tax benefit from stock options exercised		850				850
Loan to ESOP to purchase shares*				(15,000)		(15,000)
Repayment of ESOP loan*				7,030		7,030
BALANCE AT DEC. 31, 1998	<u>\$825,395</u>	<u>\$2,197,058</u>	<u>\$2,173,373</u>	<u>\$(18,503)</u>	<u>\$ (81,250)</u>	<u>\$5,096,073</u>
Net income			570,933			570,933
Recognition of unrealized loss from marketable securities, net of tax of \$4,417					6,416	6,416
Currency translation adjustments					(3,587)	(3,587)
Other comprehensive income for 1999						573,762
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(5,292)			(5,292)
Common stock			(489,813)			(489,813)
Issuances of common stock—net	12,930	92,247				105,177
Pooling of interests business combinations			4,599			4,599
Tax benefit from stock options exercised		58				58
Other	(132)	(1,109)				(1,241)
Repayment of ESOP loan*				6,897		6,897
BALANCE AT DEC. 31, 1999	<u>\$838,193</u>	<u>\$2,288,254</u>	<u>\$2,253,800</u>	<u>\$(11,606)</u>	<u>\$ (78,421)</u>	<u>\$5,290,220</u>
Net income			526,828			526,828
Currency translation adjustments					(78,508)	(78,508)
Other comprehensive income for 2000						448,320
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(4,241)			(4,241)
Common stock			(492,183)			(492,183)
Issuances of common stock—net	13,892	102,785				116,677
Tax benefit from stock options exercised		53				53
Other				16		16
Gain recognized from NRG stock offering		215,933				215,933
Loan to ESOP to purchase shares				(20,000)		(20,000)
Repayment of ESOP loan*				6,989		6,989
BALANCE AT DEC. 31, 2000	<u>\$852,085</u>	<u>\$2,607,025</u>	<u>\$2,284,220</u>	<u>\$(24,617)</u>	<u>\$ (156,929)</u>	<u>\$5,561,784</u>

* Did not affect cash flows

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CAPITALIZATION

	December 31	
	2000	1999
	(Thousands of dollars)	
LONG-TERM DEBT		
NSP-MINNESOTA DEBT		
First Mortgage Bonds, Series due:		
Dec. 1, 2000-2006, 3.50-4.10%	\$ 13,230*	\$ 15,170*
Dec. 1, 2000, 5.75%		100,000
Oct. 1, 2001, 7.875%	150,000	150,000
March 1, 2003, 5.875%	100,000	100,000
April 1, 2003, 6.375%	80,000	80,000
Dec. 1, 2005, 6.125%	70,000	70,000
April 1, 2007, 6.80%		60,000**
March 1, 2011, variable rate, 5.05% at Dec. 31, 2000, and 5.75% at Dec. 31,1999	13,700**	13,700**
March 1, 2019, variable rate, 4.25% at Dec. 31, 2000, and 3.7% at Dec. 31,1999	27,900**	27,900**
Sept. 1, 2019, variable rate, 4.36% and 4.61% at Dec. 31, 2000, and 3.71% at Dec. 31, 1999	100,000**	100,000**
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
Guaranty Agreements, Series due: Feb. 1, 1999-May 1, 2003, 5.375-7.40%	29,950**	30,650**
NSP-Minnesota Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
City of Becker Pollution Control Revenue Bonds—Series due Dec. 1, 2005, 7.25%		9,000**
City of Becker Pollution Control Revenue Bonds—Series due April 1, 2030, 5.1% at Dec. 31, 2000	69,000**	
Anoka County Resource Recovery Bond—Series Due Dec. 1, 2000-2008, 4.05-5.0%	17,990	19,615*
Employee Stock Ownership Plan Bank Loans due 2000-2007, variable rate	24,617	11,606
Other	194	1,458
Unamortized discount—net	(5,513)	(6,604)
Total	1,341,068	1,432,495
Less redeemable bonds classified as current (See Note 4)	141,600	141,600
Less current maturities	161,773	108,509
Total NSP-Minnesota long-term debt	\$1,037,695	\$1,182,386
PSCO DEBT		
First Mortgage Bonds, Series due:		
Jan. 1, 2001, 6.00%	\$ 102,667	\$ 102,667
April 15, 2003, 6.00%	250,000	250,000
March 1, 2004, 8.125%	100,000	100,000
Nov. 1, 2005, 6.375%	134,500	134,500
June 1, 2006, 7.125%	125,000	125,000
April 1, 2008, 5.625%	18,000**	18,000**
June 1, 2012, 5.5%	50,000**	50,000**
April 1, 2014, 5.875%	61,500**	61,500**
Jan. 1, 2019, 5.1%	48,750**	48,750**
July 1, 2020, 9.875%		70,000
March 1, 2022, 8.75%	147,840	148,000
Jan. 1, 2024, 7.25%	110,000	110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000
Secured Medium-Term Notes, due Feb. 1, 2001-March 5, 2007, 6.45-9.25%	226,500	256,500
Other secured long-term debt 13.25%, due in installments through Oct. 1, 2016	29,777	30,298
PSCCC Unsecured Medium-Term Notes due May 30, 2000, 5.86%		100,000
PSCCC Unsecured Medium-Term Notes due May 30, 2002, variable rate 7.40% at Dec. 31, 2000	100,000	
Unamortized Discount	(5,952)	(6,998)
Capital lease obligations, 11.2% due in installments through May 31, 2025	54,202	56,565
Total	1,752,784	1,854,782
Less current maturities	142,043	132,823
Total PSCo long-term debt	\$1,610,741	\$1,721,959

* Resource recovery financing

** Pollution control financing

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	December 31	
	2000	1999
	(Thousands of dollars)	
LONG-TERM DEBT—CONTINUED		
SPS DEBT		
First Mortgage Bonds, Series due:		
July 15, 2004, 7.25%		\$ 135,000
March 1, 2006, 6.5%		60,000
July 15, 2022, 8.25%		36,000
Dec. 1, 2022, 8.20%		89,000
Feb. 15, 2025, 8.50%		60,267
Unsecured Senior A Notes, due March 1, 2009, 6.2%	\$ 100,000	100,000
Pollution control obligations, securing pollution control revenue bonds, Not collateralized by First Mortgage Bonds due:		
July 1, 2011, 5.20%	44,500	44,500
July 1, 2016, variable rate, 5.10% at Dec. 31, 2000 and 4.7% at Dec. 31, 1999	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Less: funds held by Trustee:	(168)	(168)
Unamortized discount	(126)	(1,024)
Total SPS long-term debt	\$ 226,506	\$ 605,875
NSP-WISCONSIN DEBT		
First Mortgage Bonds Series due:		
Oct. 1, 2003, 5.75%	\$ 40,000	\$ 40,000
March 1, 2023, 7.25%	110,000	110,000
Dec. 1, 2026, 7.375%	65,000	65,000
City of La Crosse Resource Recovery Bond—Series due Nov. 1, 2021, 6%	18,600*	18,600*
Fort McCoy System Acquisition—due Oct. 31, 2030, 7%	996	
Senior Notes—due Oct. 1, 2008, 7.64%	80,000	
Unamortized discount	(1,562)	(1,650)
Total	313,034	231,950
Less current maturities	34	
Total NSP-Wisconsin long-term debt	\$ 313,000	\$ 231,950
NRG DEBT		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	\$ 239,386	
NRG Energy, Inc. Senior Notes, Series due:		
Feb. 1, 2006, 7.625%	125,000	\$ 125,000
June 15, 2007, 7.5%	250,000	250,000
June 1, 2009, 7.5%	300,000	300,000
Nov. 1, 2013, 8%	240,000	240,000
Sept. 15, 2010, 8.25%	350,000	
NRG debt secured solely by project assets:		
NRG Northeast Generating debt		646,564
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	270,000	
June 15, 2015, 8.842%	130,000	
Dec. 15, 2024, 9.292%	300,000	
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	488,750	
Sept. 15, 2024, 9.479%	300,000	
Sterling Luxembourg #3 Loan due June 30, 2019, variable rate, 7.86% at Dec. 31, 2000	346,668	
Flinders Power Finance Pty. due September 2012, various rates, 7.58% at Dec. 31, 2000	83,820	
Crockett Corp. LLP debt due Dec. 31, 2014, 8.13%	245,229	255,000
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	65,762	68,881
Various debt due 2001-2008, 0.0-10.73%	60,923	62,072
Other	1,307	18,631
Total	3,796,845	1,966,148
Less current maturities	145,504	30,524
Total NRG long-term debt	\$3,651,341	\$1,935,624

* Resource recovery financing

See Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	December 31	
	2000	1999
	(Thousands of dollars)	
LONG-TERM DEBT—CONTINUED		
OTHER SUBSIDIARIES' LONG-TERM DEBT		
First Mortgage Bonds—Cheyenne:		
Series due April 1, 2003 - Jan. 1, 2024, 7.5 - 7.875%	\$ 12,000	\$ 12,000
Industrial Development Revenue Bonds due Sept. 1, 2021 - March 1, 2027, variable rate 4.95% and 5.60% at Dec. 31, 2000 and 1999	17,000	17,000
Viking Gas Transmission Co. Senior Notes—Series due		
Oct. 31, 2008 - Sept. 30, 2014, 6.65 - 8.04%	49,941	54,702
Various Eloigne Co. Affordable Housing Project Notes due 2002 - 2024, 0.3 - 9.91%	51,309	47,116
Other	30,414	36,466
Total	160,664	167,284
Less current maturities	12,657	17,593
Total other subsidiaries long-term debt	\$ 148,007	\$ 149,691
XCEL ENERGY INC. DEBT		
Unsecured Senior Notes due Dec. 1, 2010, 7%	\$ 600,000	
Unamortized discount	(3,849)	
Total Xcel Energy Inc. debt	\$ 596,151	
Total long-term debt	\$7,583,441	\$5,827,485
MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS		
Each holding as its sole asset junior subordinated deferrable debentures of NSP-Minnesota, PSCo and SPS—(see Note 6)	\$ 494,000	\$ 494,000
CUMULATIVE PREFERRED STOCK—authorized 7,000,000 shares of \$100 par value;		
outstanding shares: 2000, 1,049,800; 1999, 1,050,000		
\$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, 2000, 99,800 shares; 1999, 100,000 shares	9,980	10,000
4.56 series, 150,000 shares	15,000	15,000
Total	104,980	105,000
Premium on preferred stock	340	340
Total preferred stockholders' equity	\$ 105,320	\$ 105,340
COMMON STOCKHOLDERS' EQUITY		
Common stock—authorized 1,000,000,000 shares of \$2.50 par value; outstanding shares: 2000, 340,834,147; 1999, 335,277,321	\$ 852,085	\$ 838,193
Premium on common stock	2,607,025	2,288,254
Retained earnings	2,284,220	2,253,800
Leveraged common stock held by ESOP—shares at cost: 2000, 1,041,180; 1999, 392,325	(24,617)	(11,606)
Accumulated other comprehensive income (loss)	(156,929)	(78,421)
Total common stockholders' equity	\$5,561,784	\$5,290,220

See Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Merger Basis of Presentation

On Aug. 18, 2000, following receipt of all required regulatory approvals, NSP and NCE merged and formed Xcel Energy Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares) and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA.

Pursuant to the merger agreement, NCE was merged with and into NSP. NSP, as the surviving legal corporation, changed its name to Xcel Energy. Also, as part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed wholly owned subsidiary of Xcel Energy, which was renamed NSP-Minnesota.

Consistent with pooling accounting requirements, results and disclosures for all periods prior to the merger have been restated for consistent reporting with post-merger organization and operations. All earnings per share amounts previously reported for NSP and NCE have been restated for presentation on an Xcel Energy share basis.

Business and System of Accounts

Xcel Energy's domestic utility subsidiaries are engaged principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. Xcel Energy and its subsidiaries are subject to the regulatory provisions of the PUHCA. The utility subsidiaries are subject to regulation by the FERC and state utility commissions. All of the utility companies' accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material aspects.

Principles of Consolidation

Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, BMG and Cheyenne. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy's regulated businesses also include Viking and WGI.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., a publicly traded independent power producer. Xcel Energy indirectly owns 82 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter 2000, when NRG completed its initial public offering.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Seren Innovations, Inc., e prime, inc., Planergy International, Inc. and Eloigne Company. Xcel Energy also reports in its nonregulated activities its 50-percent stake in Yorkshire Power.

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Energy Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy International Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc. and Xcel Energy O & M Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects. We record our portion of earnings from international investments after subtracting foreign income taxes, if applicable. In the consolidation process, we eliminate all significant intercompany transactions and balances.

Revenue Recognition

Xcel Energy records utility revenues based on a calendar month, but reads meters and bills customers according to a cycle that doesn't necessarily correspond with the calendar month's end. To compensate, we estimate and record unbilled revenues from the monthly meter-reading dates to the month's end.

Xcel Energy's utility subsidiaries have adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred.

PSCo's electric rates in Colorado are adjusted under the ICA, which takes into account changes in energy costs and certain trading gains and losses that are shared with the customer. SPS' rates in Texas and New Mexico have periodic fuel filing and reporting requirements, which can provide cost recovery. NSP-Wisconsin's rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. In Wisconsin, we can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel cost hearing process.

In Colorado, PSCo operates under an electric PBRP, which results in an annual earnings test with the sharing of excess earnings between customers and shareholders. The sharing threshold is earnings in excess of an 11-percent return on equity for 2001 and a 10.50-percent return on equity for 2002. In Texas, SPS operates under an earnings tests, in which excess earnings above a certain level are returned to the customer.

NSP-Minnesota and PSCo's rates include monthly adjustments for the recovery of conservation and energy management program costs, which are reviewed annually.

Trading Operations

Effective with year-end 2000 reporting, Xcel Energy changed its policy for the presentation of energy trading operating results. Previously, trading margins were recorded net of costs in electric and natural gas revenues. After the merger, Xcel Energy elected to report trading revenues separately from trading costs. Prior years' results have been reclassified for consistency with 2000 reporting.

Xcel Energy's trading operations are conducted mainly by PSCo and e prime. Trading revenues and costs of goods sold do not include the revenue and production costs associated with energy produced from generation assets or results from NRG.

Property, Plant, Equipment and Depreciation

Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired, plus net removal cost, is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Xcel Energy determines the depreciation of its plant by spreading the original cost equally over the plant's useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.3 percent for the years ended Dec. 31, 2000, 1999 and 1998.

Property, plant and equipment includes approximately \$18 million and \$25 million, respectively, for costs associated with the engineering design of the future Pawnee 2 generating station and certain water rights located in southeastern Colorado, also obtained for a future generating station. PSCo is earning a return on these investments based on its weighted average cost of debt in accordance with a CPUC rate order.

Allowance for Funds Used During Construction (AFDC)

AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other income and expense (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in Xcel Energy's rate base for establishing utility service rates. In addition to construction-related amounts, AFDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota. Interest capitalized as AFDC was approximately \$20 million in 2000, \$19 million in 1999 and \$25 million in 1998.

Decommissioning

Xcel Energy accounts for the future cost of decommissioning—or permanently retiring—its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full-rate recovery of the future decommissioning costs. Our decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. For more information on nuclear decommissioning, see Note 15 to the Financial Statements.

Nuclear Fuel Expense

Nuclear fuel expense, which is recorded as the plant uses fuel, includes the cost of nuclear fuel used and future spent nuclear fuel disposal, based on fees established by the U.S. Department of Energy (DOE) and NSP-Minnesota's portion of the cost of decommissioning or shutting down the DOE's fuel enrichment facility.

Environmental Costs

We record environmental costs when it is probable Xcel Energy is liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flows.

We record estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Income Taxes

Xcel Energy and its subsidiaries file consolidated federal and combined and separate state income tax returns. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. Xcel Energy defers income taxes

for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. We use the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which we summarize in Note 16 to the Financial Statements. We discuss our income tax policy for international operations in Note 8 to the Financial Statements.

Foreign Currency Translation

Xcel Energy's foreign operations generally use the local currency as their functional currency in translating international operating results and balances to U.S. currency. Foreign currency denominated assets and liabilities are translated at the exchange rates in effect at the end of a reporting period. Income, expense and cash flows are translated at weighted-average exchange rates for the period. We accumulate the resulting currency translation adjustments and report them as a component of Other Comprehensive Income. When we convert cash distributions made in one currency to another currency, we include those gains and losses in the results of operations as a component of other income.

Derivative Financial Instruments

Xcel Energy and its subsidiaries utilize a variety of derivatives, including interest rate swaps and locks, foreign currency hedges and energy contracts. The energy contracts are both financial- and commodity-based, in the energy trading and energy non-trading operations, to reduce exposure to commodity price risk. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps.

Xcel Energy and its subsidiaries adopted Emerging Issues Task Force (EITF) 98-10, "Accounting for Energy Trading and Risk Management Activities," effective Jan. 1, 1999. EITF 98-10 requires gains or losses resulting from market value changes on energy trading contracts to be recorded in earnings. The initial adoption of EITF 98-10 had an immaterial impact on Xcel Energy's net income.

Energy contracts also are utilized by Xcel Energy and its subsidiaries in non-trading operations to reduce commodity price risk. Hedge accounting is applied only if the contract reduces the price risk of the underlying hedged item and is designated as a hedge at its inception. Gains and losses related to qualifying hedges of firm commitments or anticipated transactions are deferred and recognized as a component of purchased power or cost of gas sold when settlement occurs. If, subsequent to the inception of the hedge, the underlying transactions are no longer likely to occur, the related gains and losses are recognized currently in income.

While NRG is not currently hedging investments involving foreign currency, NRG will hedge such investments when it believes that preserving the U.S. dollar value of the investment is appropriate. NRG is not hedging currency translation adjustments related to future operating results. NRG does not speculate in foreign currencies. Xcel Energy is not currently hedging its foreign currency exposure associated with its investment in Yorkshire Power.

From time to time, NRG also uses interest rate hedging instruments to protect it from an increase in the cost of borrowing. Gains and losses on interest rate hedging instruments are reported as part of the asset Investments in Unconsolidated Affiliates when the hedging instrument relates to a project that has financial statements that are not consolidated into NRG's financial statements. Otherwise, they are reported as a part of debt.

A final derivative instrument used by Xcel Energy is the interest rate swap. The cost or benefit of the interest rate swap agreements is recorded as a component of interest expense. None of these derivative financial instruments are reflected on Xcel Energy's balance sheet. For further discussion of Xcel Energy's risk management and derivative activities, see Note 13 to the Financial Statements.

Use of Estimates

In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. We use estimates for such items as plant depreciable lives, tax provisions, uncollectible amounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results. Each year we also review the depreciable lives of certain plant assets and revise them if appropriate.

Cash Equivalents

Xcel Energy considers investments in certain debt instruments—with a remaining maturity of three months or less at the time of purchase—to be cash equivalents. Those debt instruments are primarily commercial paper and money market funds.

Inventory

All inventory is recorded at average cost, with the exception of natural gas in underground storage at PSCo, which is recorded using last-in-first-out (LIFO) pricing.

Regulatory Accounting

Xcel Energy's regulated utility subsidiaries account for certain income and expense items using SFAS No. 71—"Accounting for the Effects of Certain Types of Regulation." As discussed in Note 12 to the Financial Statements, SPS' generation business no longer follows SFAS 71. Under SFAS 71:

- We defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and
- We defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific rate-making decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment.

Stock-Based Employee Compensation

Xcel Energy has several stock-based compensation plans. We account for those plans using the intrinsic value method. We do not record compensation expense for stock options because there is no difference between the market price and the purchase price at grant date. We do, however, record compensation expense for restricted stock that we award to certain employees, but hold until the restrictions lapse or the stock is forfeited. We do not use the optional accounting under SFAS No. 123—"Accounting for Stock-Based Compensation." If we had used the SFAS 123 method of accounting, earnings would have been reduced by approximately 2 cents per share for 2000 and approximately 1 cent per share per year for 1999 and 1998.

NRG Development Costs

As NRG develops projects, it expenses the development costs it incurs until a sales agreement or letter of intent is signed and the project has received NRG board approval. NRG capitalizes additional costs incurred at that point. When a project begins to operate, NRG amortizes the capitalized costs over either the life of the project's related assets or the revenue contract period, whichever is less. If a project is terminated without becoming operational, NRG expenses the capitalized costs in the period of the termination.

Intangible Assets and Deferred Financing Costs

Goodwill results when Xcel Energy purchases an entity at a price higher than the underlying fair value of the net assets. We amortize the goodwill and other intangible assets over periods consistent with the economic useful life of the assets. Our intangible assets are currently amortized over a range of 5 to 40 years. We periodically evaluate the recovery of goodwill based on an analysis of estimated undiscounted future cash flows. At Dec. 31, 2000, Xcel Energy's intangible assets included approximately \$66 million of goodwill, net of \$7 million of accumulated amortization.

Intangible and other assets also included deferred financing costs, net of amortization, of approximately \$94 million at Dec. 31, 2000. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Reclassifications

We reclassified certain items in the 1998 and 1999 income statements and the 1999 balance sheet to conform to the 2000 presentation. These reclassifications had no effect on net income or earnings per share. Reported amounts for periods prior to the merger have been restated to reflect the merger as if it had occurred as of Jan. 1, 1998.

2. MERGER COSTS AND SPECIAL CHARGES

Special Charges 2000

Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges totaling \$241 million. In the aggregate, these special charges reduced Xcel Energy's 2000 earnings by 52 cents per share. Of these pretax special charges, \$201 million, or 43 cents per share, was recorded during the third quarter of 2000, and \$40 million, or 9 cents per share, was recorded during the fourth quarter of 2000.

The pretax charges included \$52 million related to one-time transaction-related costs incurred in connection with the merger of NSP and NCE. These transaction costs include investment banker fees, legal and regulatory approval costs, and expenses for support of and assistance with planning and completing the merger transaction.

Also included were \$147 million of pretax charges pertaining to incremental costs of transition and integration activities associated with merging NSP and NCE to begin operations as Xcel Energy. These transition costs include approximately \$77 million for severance and related expenses associated with staff reductions of 721 employees, 661 of whom were released through February 2001. The staff reductions were non-bargaining positions mainly in corporate and operations support areas. Other transition and integration costs include amounts incurred for facility consolidation, systems integration, regulatory transition, merger communications and operations integration assistance.

In addition, the pretax charges include \$42 million of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy's nonregulated businesses. These special charges, which were recorded in the third quarter, include: \$22 million of write-offs of goodwill and project development costs for Planergy and Energy Masters International (EMI) energy services operations due to a change in their business focus and direction after the merger; \$10 million of contractual obligations and other costs associated with post-merger changes in the strategic operations and related revaluations of e prime's energy marketing business; and \$10 million in asset write-downs and losses resulting from various other nonregulated business ventures that would not be pursued after the merger. The write-downs were based on fair value estimates, consisting mainly of future cash flow projections.

The pretax special charges recognized for merger transaction, transition and integration activities include approximately \$66 million in costs incurred prior to third quarter 2000, which had been deferred prior to merger consummation. Consistent with pooling accounting requirements, upon

consummation of the merger to form Xcel Energy in the third quarter of 2000, Xcel Energy expensed all merger-related costs incurred up to that point.

The following table summarizes the special charges expensed during 2000.

	Expensed Without Accrual		Expense Accrued as Liability		Payments Against Liability		Dec. 31, 2000 Liability*
	3rd Qtr.	4th Qtr.	3rd Qtr.	4th Qtr.	3rd Qtr.	4th Qtr.	
	(Millions of dollars)						
Employee separation and other related costs . . .	\$ 16	\$ 3	\$52	\$6		\$(10)	\$48
Regulatory transition costs	4	2	5	1		(1)	5
Other transition and integration costs	33	23	—	2	—	—	2
Total merger transition and integration costs	53	28	57	9		(11)	55
Transaction-related merger costs	49	3					
Nonregulated asset disposals and abandonments	22						
Nonregulated goodwill impairment	20	—	—	—	—	—	—
Total nonregulated asset impairments	42	—	—	—	—	—	—
Total special charges	<u>\$144</u>	<u>\$31</u>	<u>\$57</u>	<u>\$9</u>	<u>—</u>	<u>\$(11)</u>	<u>\$55</u>

* Reported on the balance sheet in other current liabilities.

Special Charges 1999

EMI Goodwill In December 1999, Xcel Energy recorded a pretax charge (reported in special charges) of approximately \$17 million, or 4 cents per share, to write off all goodwill that was recorded by its subsidiary EMI for its acquisitions of Energy Masters Corp. in 1995 and Energy Solutions International in 1997. This charge reflected a revised business outlook based on the levels of contract signings by EMI.

Loss on Marketable Securities During 1999, Xcel Energy recorded pretax charges (reported in special charges) of approximately \$14 million, or 3 cents per share, for valuation write-downs on its investment in the publicly traded common stock of CellNet Data Systems, Inc. In October 1999, CellNet announced it was experiencing financial difficulties and was contemplating restructuring its capital financing. In February 2000, CellNet filed for Chapter 11 bankruptcy protection. CellNet's assets were subsequently acquired by another company.

3. SHORT-TERM BORROWINGS

Notes Payable and Commercial Paper

Information regarding notes payable and commercial paper for the years ended Dec. 31, 2000 and 1999, is:

	2000	1999
	(Millions of dollars, except interest rates)	
Notes payable to banks	\$ 20	\$ 399
Commercial paper	1,455	1,034
Total short-term debt	<u>\$1,475</u>	<u>\$1,433</u>
Weighted average interest rate at year end	6.48%	6.37%

Bank Lines of Credit and Compensating Bank Balances

At Dec. 31, 2000, Xcel Energy and its subsidiaries had approximately \$3.0 billion in unsecured revolving credit facilities with several banks. Arrangements by Xcel Energy and its subsidiaries for committed lines of credit are maintained by a combination of fee payments and compensating balances.

In November 2000, Xcel Energy closed on two revolving credit facilities totaling \$800 million. These facilities are comprised of a \$400 million, 364-day maturity and a \$400 million, five-year maturity. They are available for Xcel's general corporate purposes, primarily supporting commercial paper borrowings.

In July 2000, NSP-Minnesota closed on a \$300 million, 364-day revolving credit facility. This facility provides short-term financing in the form of bank loans and letters of credit, but its primary purpose is support for commercial paper borrowings.

In July 2000, PSCo and its subsidiary, Public Service of Colorado Credit Corporation (PSCCC), entered into a \$600 million, 364-day revolving credit agreement that provides for direct borrowings, but whose primary purpose is to support the issuance of commercial paper by PSCo and PSCCC.

In July 2000, SPS entered into a \$500-million credit agreement that is effective through January 2002. This credit facility was initially used as support for the issuance of commercial paper to fund open market purchases, tender and defeasance of SPS' outstanding first mortgage bonds and other related restructuring costs. SPS is the initial borrower under this credit agreement; however, at the time of separation of the generation assets, the obligations under this credit agreement will be assumed by a newly formed generation company. See Note 12 to the Financial Statements for more information on restructuring.

In February 2001, SPS renewed a \$300 million, 364-day revolving credit facility. This facility provides for direct borrowings, but its primary purpose is to support the issuance of commercial paper.

In January 2001, NRG entered into a \$600-million bridge credit facility to provide financing for its LS Power acquisition. It is expected to be repaid with the proceeds of NRG's planned common stock and equity unit offerings. The credit facility expires Dec. 31, 2001.

NRG has a \$500-million revolving credit facility under a commitment fee arrangement that matures in March 2001. This facility provides short-term financing in the form of bank loans. At Dec. 31, 2000, NRG had \$8 million outstanding under this facility.

NRG has a \$125-million syndicated letter of credit facility that matures in November 2003. At Dec. 31, 2000, NRG had \$58 million outstanding under this facility.

4. LONG-TERM DEBT

Except for SPS and other minor exclusions, all property of Xcel Energy's utility subsidiaries is subject to the liens of its first mortgage indentures, which are contracts between the companies and their bond holders. In addition, certain SPS payments under its pollution control obligations are pledged to secure obligations of the Red River Authority of Texas.

The annual sinking-fund requirements of Xcel Energy's utility subsidiaries' first mortgage indentures are the amounts necessary to redeem 1 to 1.5 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding series issued for pollution control and resource recovery financings and certain other series totaling \$2 billion.

NSP-Minnesota, NSP-Wisconsin, PSCo and Cheyenne expect to satisfy substantially all of their sinking-fund obligations in accordance with the terms of their respective indentures through the application of property additions. SPS has no significant sinking-fund requirements.

NSP-Minnesota's 2011 and 2019 series first mortgage bonds 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 2011 series bonds are redeemable upon seven-days notice at the

option of the bondholder. NSP-Minnesota also is potentially liable for repayment of the 2019 series when the bonds are tendered, which occurs each time the variable interest rates change. The principal amount of all of these variable rate bonds outstanding represents potential short-term obligations and, therefore, is reported under current liabilities on the balance sheets.

Maturities and sinking-fund requirements for Xcel Energy's long-term debt are:

• 2001	\$605 million
• 2002	\$311 million
• 2003	\$663 million
• 2004	\$267 million
• 2005	\$286 million

5. PREFERRED STOCK

At Dec. 31, 2000, Xcel Energy had various preferred stock series, which were callable at prices per share ranging from \$102 to \$103.75, plus accrued dividends.

PSCo has 10 million shares of cumulative preferred stock, \$0.01 par value, authorized. At Dec. 31, 2000 and 1999, PSCo had no shares of preferred stock outstanding.

SPS has 10 million shares of cumulative preferred stock, \$1 par value, authorized. At Dec. 31, 2000 and 1999, SPS had no shares of preferred stock outstanding.

6. MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

In 1996, SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, issued \$100 million of 7.85 percent trust preferred securities that mature in 2036. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by SPS and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. Distributions and redemption payments are guaranteed by SPS.

In 1997, NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, issued \$200 million of 7.875 percent trust preferred securities that mature in 2037. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by NSP-Minnesota and held by the subsidiary trust, which are eliminated in consolidation. The preferred securities are redeemable at \$25 per share beginning in 2002. Distributions and redemption payments are guaranteed by NSP-Minnesota.

In 1998, PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, issued \$194 million of 7.60 percent trust preferred securities that mature in 2038. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by PSCo and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of PSCo after May 2003, at 100 percent of the principal amount outstanding plus accrued interest. Distributions and redemption payments are guaranteed by PSCo.

Distributions paid to preferred security holders are reflected as a financing cost in the Consolidated Income Statements along with interest expense.

7. JOINT PLANT OWNERSHIP

The investments by Xcel Energy's utility subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2000, are as follows:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
(Thousands of dollars)				
NSP-MINNESOTA —Sherco Unit 3	\$607,568	\$252,096	\$1,095	59.0
PSCO:				
Hayden Unit 1	82,800	35,767	1,172	75.5
Hayden Unit 2	78,347	39,058	161	37.4
Hayden Common Facilities	27,145	2,071	258	53.1
Craig Units 1 & 2	57,710	29,248		9.7
Craig Common Facilities Units 1, 2 & 3	21,012	8,339	(21)	6.5-9.7
Transmission Facilities, including Substations	81,769	27,349	609	42.0-73.0
Total PSCo	\$348,783	\$141,832	\$2,179	
NRG —Big Cajun II Unit 3	\$179,100	\$ 3,400		58.0

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt coal-fired electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of related expenses for Sherco 3 is included in Utility Operating Expenses. The PSCo assets include approximately 320 megawatts of generating capacity. PSCo is responsible for its proportionate share of operating expenses (reflected in the Consolidated Statements of Income) and construction expenditures. NRG is responsible for its proportionate share of operating expenses and construction expenditures.

8. 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:

	2000	1999	1998
Federal statutory rate	35.0 %	35.0 %	35.0 %
INCREASES (DECREASES) IN TAX FROM:			
State income taxes, net of federal income tax benefit	5.8 %	2.1 %	2.8 %
Life insurance policies	(2.4)%	(2.3)%	(1.7)%
Tax credits recognized	(10.2)%	(6.0)%	(4.6)%
Equity income from unconsolidated affiliates	(2.7)%	(5.5)%	(4.9)%
Regulatory differences—utility plant items	2.3 %	1.9 %	1.0 %
Deferred tax expense on Yorkshire investment	2.3 %		
Non-deductibility of merger costs	2.9 %		
Other—net	1.8 %	(1.3)%	0.2 %
Effective income tax rate including extraordinary items	34.8 %	23.9 %	27.8 %
Extraordinary items	1.0 %		
Effective income tax rate excluding extraordinary items	35.8 %	23.9 %	27.8 %

	2000	1999	1998
	(Thousands of dollars)		
INCOME TAXES COMPRISE THE FOLLOWING EXPENSE			
(BENEFIT) ITEMS:			
Current federal tax expense	\$205,718	\$175,461	\$238,124
Current state tax expense	63,428	26,949	34,454
Current foreign tax expense	(625)	4,040	2,358
Current federal tax credits	(71,270)	(30,137)	(25,122)
Deferred federal tax expense	103,258	27,380	9,940
Deferred state tax expense	12,547	(2,352)	3,027
Deferred foreign tax expense	7,104	(6,868)	(7,736)
Deferred investment tax credits	(15,295)	(14,800)	(14,654)
Income tax expense excluding extraordinary items	304,865	179,673	240,391
Tax expense on extraordinary items	8,549		
Total income tax expense	<u>\$296,316</u>	<u>\$179,673</u>	<u>\$240,391</u>

Xcel Energy management intends to indefinitely reinvest earnings from NRG's foreign operations. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately \$238 million and \$195 million at Dec. 31, 2000 and 1999. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

Xcel Energy does not intend to indefinitely reinvest earnings from its investment in Yorkshire Power and, therefore, has provided deferred taxes of \$20 million on unremitted earnings of \$55 million at Dec. 31, 2000. Prior to 2000, management did intend to reinvest Yorkshire Power earnings indefinitely, and thus no taxes were provided on unremitted earnings of \$11 million at Dec. 31, 1999.

The components of Xcel Energy's net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2000	1999
	(Thousands of dollars)	
DEFERRED TAX LIABILITIES:		
Differences between book and tax bases of property	\$1,754,928	\$1,739,394
Regulatory assets	168,380	143,187
Partnership income/loss	70,266	36,756
Tax benefit transfer leases	18,839	23,431
Other	98,263	106,932
Total deferred tax liabilities	<u>\$2,110,676</u>	<u>\$2,049,700</u>
DEFERRED TAX ASSETS:		
Regulatory liabilities	\$ 88,817	\$ 71,471
Employee benefits	14,675	13,493
Deferred investment tax credits	76,133	83,061
Other	87,116	103,041
Total deferred tax assets	<u>\$ 266,741</u>	<u>\$ 271,066</u>
Net deferred tax liability	<u>\$1,843,935</u>	<u>\$1,778,634</u>

9. COMMON STOCK AND INCENTIVE STOCK PLANS

Incentive Stock Plans

We and some of our subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate our earnings per share includes the dilutive effect of stock options and other stock awards based on the treasury stock method. The tables below include awards made by us and some of our predecessor companies. Stock options issued under NCE, PSCo and SPS plans before the merger have been adjusted for the merger stock exchange ratio and are presented on an Xcel Energy share basis.

Stock Options and Performance Awards at Dec. 31, 2000 (Thousands)	2000		1999		1998	
	Awards	Average Price	Awards	Average Price	Awards	Average Price
Outstanding at beginning of year	8,490	\$25.12	6,156	\$26.15	5,439	\$24.92
Granted	6,980	25.31	2,545	22.64	1,456	29.19
Exercised	(453)	20.33	(90)	18.72	(636)	22.36
Forfeited	(704)	25.70	(111)	30.10	(94)	28.15
Expired	(54)	22.62	(10)	25.64	(9)	23.24
Outstanding at end of year	14,259	\$25.35	8,490	\$25.12	6,156	\$26.15
Exercisable at end of year	8,221	\$24.46	5,301	\$25.84	4,405	\$25.14
	Range of Exercise Prices at Dec. 31, 2000					
	\$16.60 to \$21.75		\$22.50 to \$27.99		\$28.00 to \$31.00	
Options outstanding:*						
Number outstanding	3,245,478		9,616,092		1,388,878	
Weighted average remaining contractual life (years) . .	7.6		8.3		7.4	
Weighted average exercise price	\$19.82		\$26.44		\$30.67	
Options exercisable:*						
Number exercisable	2,820,681		4,212,023		1,180,324	
Weighted average exercise price	\$19.78		\$25.86		\$30.65	

* There were also 8,259 other awards outstanding at Dec. 31, 2000.

Certain employees also may be awarded restricted stock under Xcel Energy's incentive plans. We hold restricted stock until restrictions lapse; 50 percent of the stock vests one year from the date of the award and the other 50 percent vests two years from the date of the award. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment. We granted 58,690 restricted shares in 2000, 52,688 restricted shares in 1999 and 49,651 restricted shares in 1998. Compensation expense related to these awards was immaterial.

The NCE/NSP merger was a "change in control" under the NSP incentive plan, so all stock option and restricted stock awards under that plan became fully vested and exercisable as of the merger date. The NCE/NSP merger did not constitute a change in control under the NCE incentive plans, so there was no accelerated vesting of stock options issued under them. When NCE and NSP merged, each outstanding NCE stock option was converted to 1.55 Xcel Energy options.

We apply Accounting Principles Board Opinion No. 25 in accounting for its stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options as the exercise price of the options equals the fair-market value of our common stock at the date of grant. If we had used the SFAS 123 method of accounting, earnings would have been reduced by approximately 2 cents per share for 2000 and approximately 1 cent per share per year for 1999 and 1998.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes Option-Pricing Model with the following assumptions:

	2000	1999	1998
Expected option life	3-5 years	5-10 years	5-10 years
Stock volatility	15%	15-21%	14-15%
Risk-free interest rate	5.3-6.5%	4.7-6.4%	5.1-5.6%
Dividend yield	5.4-7.5%	5.4%	5.2-5.4%

Dividend Restrictions

The Articles of Incorporation of both NSP-Minnesota and Xcel Energy place restrictions on the amount of common stock dividends they can pay when preferred stock is outstanding. NSP-Minnesota has no outstanding preferred stock, so these restrictions would not apply. Xcel Energy has outstanding preferred stock. It could have paid approximately \$2.75 billion in additional common stock dividends before restrictions would apply.

In addition, NSP-Minnesota’s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than \$800 million in additional cash dividends on common stock at Dec. 31, 2000.

Shareholder Rights

In 2000, Xcel Energy adopted a shareholder protection rights plan. This rights plan is subject to approval by the SEC. The plan is designed to protect shareholders’ interests in the event we are ever confronted with an unfair or inadequate acquisition proposal. Pursuant to this plan and assuming SEC approval, each share of common stock has one right entitling the holder to purchase a share of Xcel Energy common stock under certain circumstances. The rights become exercisable if any person or group acquires 15 percent or more of Xcel Energy’s common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of Xcel Energy common stock or common stock of any acquirer of Xcel Energy at a reduced percentage of market value. The rights are scheduled to expire in 2011.

10. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 45 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2000, NSP-Minnesota and NSP-Wisconsin had 2,598 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 1,969 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 776 union employees covered under a collective-bargaining agreement, which expires in October 2002.

Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility employees. Benefits are based on a combination of years of service, the employee’s average pay and Social Security benefits.

Xcel Energy’s policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities.

A comparison of the actuarially computed pension benefit obligation and plan assets at Dec. 31, 2000 and 1999, for all Xcel Energy plans on a combined basis is presented in the following table.

	<u>2000</u>	<u>1999</u>
	(Thousands of dollars)	
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	\$ 2,170,627	\$ 2,157,255
Service cost	59,066	63,674
Interest cost	172,063	154,619
Acquisitions	52,800	
Plan amendments	2,649	184,255
Actuarial (gain) loss	1,327	(225,355)
Benefit payments	<u>(204,394)</u>	<u>(163,821)</u>
Obligation at Dec. 31	<u>\$ 2,254,138</u>	<u>\$ 2,170,627</u>
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	\$ 3,763,293	\$ 3,460,740
Actual return on plan assets	91,846	466,374
Acquisitions	38,412	
Benefit payments	<u>(204,394)</u>	<u>(163,821)</u>
Fair value of plan assets at Dec. 31	<u>\$ 3,689,157</u>	<u>\$ 3,763,293</u>
FUNDED STATUS AT DEC. 31		
Net asset	\$ 1,435,019	\$ 1,592,666
Unrecognized transition (asset) obligation	(16,631)	(23,945)
Unrecognized prior-service cost	228,436	247,632
Unrecognized (gain) loss	<u>(1,421,690)</u>	<u>(1,680,616)</u>
Prepaid pension asset recorded	<u>\$ 225,134</u>	<u>\$ 135,737</u>
	<u>2000</u>	<u>1999</u>
SIGNIFICANT ASSUMPTIONS		
Discount rate	7.75%	7.5-8.0%
Expected long-term increase in compensation level	4.50%	4.0-4.5%
Expected average long-term rate of return on assets	8.5-10.0%	8.5-10.0%

The components of net periodic pension cost (credit) for Xcel Energy plans are:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Thousands of dollars)		
Service cost	\$ 59,066	\$ 63,674	\$ 55,545
Interest cost	172,063	154,619	145,574
Expected return on plan assets	(292,580)	(259,074)	(233,191)
Amortization of transition asset	(7,314)	(7,314)	(7,314)
Amortization of prior-service cost	19,197	17,855	6,209
Amortization of net gain	<u>(60,676)</u>	<u>(40,217)</u>	<u>(30,607)</u>
Net periodic pension cost (credit) under SFAS 87	\$(110,244)	\$ (70,457)	\$ (63,784)
Credits not recognized due to effects of regulation	<u>49,697</u>	<u>36,469</u>	<u>35,545</u>
Net benefit cost (credit) recognized for financial reporting	<u>\$ (60,547)</u>	<u>\$ (33,988)</u>	<u>\$ (28,239)</u>

Additionally, Xcel Energy maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy's operating cash flows.

Defined Contribution Plans

Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately \$23 million in 2000 and \$21 million annually in 1999 and 1998.

Xcel Energy has a leveraged ESOP that covers substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy makes contributions to this noncontributory, defined contribution plan to the extent we realize a tax savings from dividends paid on certain ESOP shares. ESOP contributions have no material effect on Xcel Energy earnings because the contributions are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocates leveraged ESOP shares to participants when it repays ESOP loans with dividends on stock held by the ESOP.

Xcel Energy's leveraged ESOP held 12.0 million shares of Xcel Energy common stock at the end of 2000 and 11.3 million shares of Xcel Energy common stock at the end of 1999 and 1998. Xcel Energy excluded the following uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2000, 0.5 million in 1999 and 0.6 million in 1998.

Postretirement Health Care Benefits

Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees. The NSP plan was terminated for nonbargaining employees retiring after 1998 and for bargaining employees after 1999.

In conjunction with the 1993 adoption of SFAS No.106—"Employers' Accounting for Postretirement Benefits Other Than Pensions," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS 106. PSCo transitioned to full accrual accounting for SFAS 106 costs between 1993 and 1997, consistent with the accounting requirements for rate regulated enterprises. The Colorado jurisdictional SFAS 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS 106 costs, with regulatory differences fully amortized prior to 1997.

Additionally, certain state agencies, which regulate Xcel Energy's utility subsidiaries, have issued guidelines related to the funding of SFAS 106 costs. SPS is required to fund SFAS 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo and Cheyenne are required to fund SFAS 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Minnesota and Wisconsin retail regulators require external funding of accrued SFAS 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed income securities and cash equivalents.

A comparison of the actuarially computed benefit obligation and plan assets at Dec. 31, 2000 and 1999, for all Xcel Energy postretirement health care plans is presented in the following table.

	<u>2000</u>	<u>1999</u>
	(Thousands of dollars)	
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	\$ 533,458	\$ 616,957
Service cost	5,679	4,680
Interest cost	43,477	35,583
Acquisitions	16,445	
Plan amendments		(80,840)
Plan participants' contributions	4,358	3,818
Actuarial (gain) loss	10,501	(5,581)
Benefit payments	<u>(37,191)</u>	<u>(41,159)</u>
Obligation at Dec. 31	<u>\$ 576,727</u>	<u>\$ 533,458</u>
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	\$ 201,767	\$ 180,742
Actual return on plan assets	10,069	11,981
Plan participants' contributions	4,358	3,818
Employer contributions	44,263	34,652
Benefit payments	<u>(37,191)</u>	<u>(29,426)</u>
Fair value of plan assets at Dec. 31	<u>\$ 223,266</u>	<u>\$ 201,767</u>
FUNDED STATUS AT DEC. 31		
Net obligation	\$ 353,461	\$ 331,691
Unrecognized transition asset (obligation)	(202,871)	(219,644)
Unrecognized prior-service credit	13,789	14,999
Unrecognized gain (loss)	<u>(11,126)</u>	<u>5,559</u>
Accrued benefit liability recorded	<u>\$ 153,253</u>	<u>\$ 132,605</u>
	<u>2000</u>	<u>1999</u>
SIGNIFICANT ASSUMPTIONS:		
Discount rate	7.75%	7.5-8.0%
Expected average long-term rate of return on assets	8.0-9.5%	8.0-9.5%

The assumed health care cost trend rate for 2000 is approximately 7.5 percent, decreasing gradually to 5.5 percent in 2004 and remaining level thereafter. A 1-percent increase in the assumed health care cost trend rate would increase the estimated total accumulated benefit obligation for Xcel Energy by approximately \$49.3 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately \$3.8 million. A 1-percent decrease in the assumed health care cost trend rate would decrease the estimated total accumulated benefit obligation for Xcel Energy by approximately \$42.9 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately \$3.3 million.

The components of net periodic postretirement benefit cost of all Xcel Energy's plans are:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Thousands of dollars)		
Service cost	\$ 5,679	\$ 4,680	\$ 8,164
Interest cost	43,477	35,583	42,399
Expected return on plan assets	(17,902)	(15,003)	(12,349)
Amortization of transition obligation	16,773	17,461	23,411
Amortization of prior-service cost (credit)	(1,211)	(1,803)	(932)
Amortization of net loss (gain)	915	(5)	(790)
Net periodic postretirement benefit costs under SFAS 106	<u>47,731</u>	<u>40,913</u>	<u>59,903</u>
Additional cost recognized due to effects of regulation	6,641	4,029	5,673
Net cost recognized for financial reporting	<u>\$ 54,372</u>	<u>\$ 44,942</u>	<u>\$ 65,576</u>

11. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Xcel Energy's nonregulated subsidiaries have investments in various international and domestic energy projects, and domestic affordable housing and real estate projects. We use the equity method of accounting for such investments in affiliates, which include joint ventures and partnerships. That's because the ownership structure prevents Xcel Energy from exercising a controlling influence over the projects' operating and financial policies. Under this method, Xcel Energy records its portion of the earnings or losses of unconsolidated affiliates as equity earnings. A summary of Xcel Energy's significant equity method investments is listed in the following table.

<u>Name</u>	<u>Geographic Area</u>	<u>Economic Interest</u>
Loy Yang Power A	Australia	25.37%
Enfield Energy Centre	Europe	25.00%
Yorkshire Power	Europe	50.00%
Gladstone Power Station	Australia	37.50%
COBEE (Bolivian Power Co. Ltd.)	South America	49.10%
MIBRAG mbH	Europe	33.33%
Cogeneration Corp. of America	USA	20.00%
Schkopau Power Station	Europe	20.95%
Long Beach Generating	USA	50.00%
El Segundo Generating	USA	50.00%
Encina	USA	50.00%
San Diego Combustion Turbines	USA	50.00%
Energy Developments Limited	Australia	29.14%
Scudder Latin American Power	Latin America	6.63%
Various independent power production facilities	USA	45-50%
Various affordable housing limited partnerships	USA	20-99.9%

The following table summarizes financial information for these projects, including interests owned by Xcel Energy and other parties for the years ended Dec. 31.

RESULTS OF OPERATIONS

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Millions of dollars)		
Operating revenues	\$4,664	\$4,087	\$3,791
Operating income	\$ 464	\$ 516	\$ 530
Net income (losses)	\$ 447	\$ 290	\$ 220
Xcel Energy's equity earnings of unconsolidated affiliates	<u>\$ 184</u>	<u>\$ 113</u>	<u>\$ 119</u>

FINANCIAL POSITION

	<u>2000</u>	<u>1999</u>
	(Millions of dollars)	
Current assets	\$ 1,590	\$ 1,198
Other assets	10,939	10,877
Total assets	<u>\$12,529</u>	<u>\$12,075</u>
Current liabilities	\$ 1,833	\$ 1,384
Other liabilities	6,806	7,719
Equity	<u>3,890</u>	<u>2,972</u>
Total liabilities and equity	<u>\$12,529</u>	<u>\$12,075</u>

Subsequent Event

In late February 2001, Xcel Energy reached an agreement in principle to sell at book value all of its investment in Yorkshire Power except for an interest of approximately 5 percent. Xcel Energy is retaining this interest to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Following completion of the transaction, proceeds of the sale will be used by Xcel Energy to pay down short-term debt and eliminate an equity issuance planned for the second half of 2001.

12. ELECTRIC UTILITY RESTRUCTURING

Restructuring legislation has been enacted in Texas and New Mexico, as summarized below. SPS has made, and continues to make, filings with the PUCT and the New Mexico Public Regulation Commission (NMPRC) to address critical issues related to SPS transition plans to implement retail competition.

New Mexico Restructuring In April 1999, New Mexico enacted the Electric Utility Restructuring Act of 1999, which provides for customer choice. The legislation provides for recovery of no less than 50 percent of stranded costs for all utilities. Transition costs must be approved by the NMPRC prior to being recovered through a non-bypassable wires charge, which must be included in transition plan filings. SPS must separate its utility operations into at least two entities: energy generation and competitive services, and transmission and distribution utility services, either by the creation of separate affiliates that may be owned by a common holding company or by the sale of assets to one or more third parties. A regulated company, in general, is prohibited from providing unregulated services. In May 2000, the NMPRC approved:

- Customer choice for residential, small commercial and educational customers by January 2002;
- Customer choice for commercial and industrial customers by July 2002; and
- Completion of SPS corporate separation by August 2001.

The NMPRC has reopened its electric restructuring rulemakings to consider the impacts on New Mexico electricity markets arising from the volatile California electricity market conditions. In addition, in February 2001, the New Mexico Senate approved a bill that would delay the implementation of restructuring and retail choice until 2007. The House has yet to act on the proposal to delay. We cannot predict the changes that may result from reconsideration of the restructuring legislation or the NMPRC's reconsideration of its regulations as a result of the continuing and significant conditions in the California markets.

Texas Restructuring In June 1999, an electric utility restructuring act (SB-7) was passed in Texas, which provides for the implementation of retail competition for most areas of the state, including SPS' service area, beginning January 2002. The PUCT can delay the date for full retail competition if a

power region is unable to offer fair competition and reliable service during the 2001 pilot projects. The legislation requires:

- A rate freeze for all customers until January 2002;
- An annual earnings test through 2001;
- A 6-percent rate reduction for those residential and small commercial customers who choose not to switch suppliers at the start of retail competition;
- The unbundling of business activities, costs and rates relating to generation, transmission and distribution, and retail services;
- Reductions in NO_x and SO₂ emissions; and
- The recovery of stranded costs.

SB-7 requires each utility to unbundle its business activities into three separate legal entities: a power generation company, a regulated transmission and distribution company, and a retail electric provider. SB-7 limits the market share that a single generation provider can control to 20 percent of the generating capacity within a qualified power region. The establishment of a qualified power region with multiple generation suppliers is required under SB-7 in order to implement full retail competition. SPS must return any excess earnings above its last allowed rate of return for 1999, 2000 and 2001, or alternatively may direct any excess earnings to improvements in transmission and distribution facilities, to capital expenditures to improve air quality or to accelerate the amortization of regulatory assets, subject to PUCT approval.

The Texas legislature is currently considering amendments to SB-7 that would delay the implementation of business separation and customer choice in SPS' market area for 5 years.

Implementation SPS filed its business separation plan in Texas during the first quarter of 2000 for the unbundling of power generation, transmission, and distribution and retail electric provider services. In April 2000, the PUCT approved SPS' business separation plan. The plan provides for the separation of all competitive energy services, the establishment of an Xcel Energy customer care company, which will provide customer services for all of Xcel Energy's operating utilities, and a formal code of conduct and compliance manual for managing affiliate transactions.

Subject to all required approvals and indebtedness restrictions, it is anticipated that all generation-related and certain other assets and liabilities will be transferred at net book value to newly formed affiliates in accordance with SPS' business separation plan. It is expected that SPS and its affiliates will be capitalized consistent with their respective business operations.

In April 2000, SPS filed with the PUCT a stipulation agreement that specifically addresses SPS' implementation plans to meet the requirements of the Texas restructuring legislation. The stipulation provides for the implementation of full retail customer choice by SPS in its Texas service region, including the future divestiture of certain SPS generation assets. Subject to certain market conditions and confirmation by the SEC that the sale would not violate pooling accounting treatment, SPS agreed to divest at least 1,750 megawatts by January 2002, and specifically identified the plants that it would sell in connection with additional divestitures required to establish a qualified power region under SB-7. In subsequent discussions, the SEC has indicated that the sale of generation assets prior to August 2002 would violate pooling accounting. For SPS to comply with this qualified power region requirement and to implement full customer choice in Texas, between 2,843 megawatts and 3,184 megawatts of existing power generation assets or capacity must be sold to third-party non-affiliates. SPS has committed to complete these divestitures by January 2006. In May 2000, the PUCT issued an order approving the stipulation. SPS has committed to transfer functional control of its electric transmission system to a regional transmission organization that will operate the transmission systems of multiple owners in the central United States.

SPS filed a rate case in March 2000 to set the rates for distribution services in Texas, which are to be unbundled and implemented in January 2002. SPS requested recovery of all jurisdictional costs

associated with restructuring in Texas. Hearings and a final rate order are not expected before August 2001.

In June 2000, SPS filed its transition plan with the NMPRC. SPS filed to establish rates for the transmission and distribution business in New Mexico, requesting approval of its corporate restructuring/separation and other associated matters. Hearings were held in October and November 2000. Final approval is not expected until mid-2001.

Financial Impact With the issuance of a final written order by the PUCT in May 2000, addressing the implementation of electric utility restructuring, SPS discontinued regulatory accounting under SFAS 71 for the generation portion of its business during the second quarter of 2000. Consistent with current accounting rules, this resulted in extraordinary charges in the second and third quarters of 2000. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and liabilities, totaling approximately \$19.3 million before taxes. This resulted in an after-tax extraordinary charge of approximately \$13.7 million against the earnings of Xcel Energy and SPS. During the third quarter of 2000, SPS recorded an extraordinary charge of \$8.2 million before tax, or \$5.3 million after tax, related to the tender offer and defeasance of approximately \$295 million of first mortgage bonds. The first mortgage bonds were defeased to facilitate SPS' eventual divestiture of generation assets.

SPS transmission and distribution business continues to meet the requirements of SFAS 71, as that business is expected to remain regulated.

Additionally, there may be other significant financial implications of implementing SB-7 and electric restructuring in New Mexico. These implications include, but are not limited to, investments in information technology, establishing an independent operation of the electric transmission systems, implementing the procedures to govern affiliate transactions, the pricing of unbundled energy services and the regulatory recovery of incurred costs related to these issues. These costs could be as much as \$75 million. The total impacts of restructuring are unknown at this time and may have a significant financial impact on the financial position, results of operations and cash flows of Xcel Energy and SPS.

13. FINANCIAL INSTRUMENTS

Fair Values

The estimated Dec. 31 fair values of Xcel Energy's recorded financial instruments are as follows:

	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Mandatorily redeemable preferred securities	\$ 494,000	\$ 481,270	\$ 494,000	\$ 427,240
Long-term investments	\$ 625,616	\$ 624,989	\$ 543,300	\$ 538,926
Long-term debt, including current portion	\$8,187,052	\$8,131,139	\$6,258,534	\$5,997,522

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 Xcel Energy's long-term investments, mainly debt securities in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair value of Xcel Energy's long-term debt and the mandatorily redeemable preferred securities are estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair-value estimates presented are based on information available to management as of Dec. 31, 2000 and 1999. These fair-value estimates have not been comprehensively revalued for purposes of these financial statements since that date, and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

Xcel Energy has entered into a construction contract guarantee that assures Quixx's performance under its engineering, procurement and construction contract with Borger Energy Associates, LP (BEA). Quixx, which owns 45 percent of BEA, is constructing a 230-megawatt cogeneration facility at a Phillips Petroleum site near Borger, Texas. The maximum aggregate amount of this guarantee at Dec. 31, 2000, was \$88.4 million. This maximum amount decreases to \$25 million at commercial operation of the facility and remains in effect for a period of no longer than 24 months before expiring.

In July 1999, Xcel Energy entered into a guarantee resulting from non-completion of certain milestone achievements within required dates in connection with the Quixx Linden cogeneration plant. The guarantee, totaling approximately \$7.5 million, is for the benefit of Bank One and all other lenders in Quixx Linden, LP. Once the milestone events are accomplished, the guarantee is required to remain for six months.

As of Dec. 31, 2000, Xcel Energy had outstanding approximately \$190 million of guarantees relating to e prime. These guarantees were made to facilitate e prime's natural gas marketing and trading activities.

As of Dec. 31, 2000, Xcel Energy provided guarantees for EMI of approximately \$27 million. Approximately \$12 million of these guarantees related to energy conservation projects in which EMI has guaranteed certain energy savings to the customer. As energy savings are realized each year due to these projects, the value of the guarantee decreases until it reaches zero in 2017. Approximately \$15 million of the guarantees relates to EMI's line of credit with US Bank.

The Bank of New York has provided a letter of credit, at the request of Xcel Energy, of approximately \$1.0 million to fulfill debt service reserve requirements as support for a Young Gas Storage Co., Ltd. loan. Young Gas Storage entered into a \$30.7-million credit agreement with various lending institutions in March 1999 with a maturity of March 2014. The loan was incurred for the development and construction of an underground natural gas storage facility in northeastern Colorado. Separately, Xcel Energy has guaranteed up to \$4.5 million to cover costs of expenses related to the project.

NSP-Minnesota has sold a portion of its other receivables to a third party. The portion of the receivables sold consisted of customer loans to local and state government entities for energy efficiency improvements under various conservation programs offered by NSP-Minnesota. Under the sales agreements, NSP-Minnesota is required to guarantee repayment to the third party of the remaining loan balances. At Dec. 31, 2000, the outstanding balance of the loans was approximately \$18.1 million. Based on prior collection experience of these loans, NSP-Minnesota believes that losses under the loan guarantees, if any, would have an immaterial impact on the results of operations.

In connection with an agreement for the sale of electric power, SPS guaranteed certain obligations of a customer totaling approximately \$27.8 million at Dec. 31, 2000. These obligations related to the construction of certain utility property that, in the event of default by the customer, would revert to SPS.

In June 2000, Xcel Energy entered into a guarantee on behalf of BNP Paribas in connection with a letter of credit provided by BNP Paribas at the request of SPS in the amount of \$5 million, expiring March 2002. The letter of credit is required to indemnify former SPS board of directors.

Derivatives

As of Dec. 31, 2000, NRG had four interest rate swap agreements with notional amounts totaling approximately \$533 million. If the swaps had been discontinued on Dec. 31, 2000, NRG would have owed the counterparties approximately \$31 million. NRG believes that its exposure to credit risk due to nonperformance by the counterparties to the hedging contracts is insignificant. These swaps are described below.

- A swap effectively converts a \$16-million issue of non-recourse variable rate debt into fixed-rate debt. The swap expires in September 2002 and is secured by the Camas Power Boiler assets.
- A swap converts \$178 million of non-recourse variable rate debt into fixed-rate debt. The swap expires in December 2014 and is secured by the Crockett Cogeneration assets.
- A swap converts £188 million, the equivalent of \$281 million, of non-recourse variable rate debt into fixed-rate debt. The swap expires in June 2019 and is secured by the Killingholme assets.
- A swap converts variable rate debt to fixed rate debt. The notional amount is AUD 105 million, the equivalent of \$59 million as of Dec. 31, 2000. The swap expires in September 2012 and is secured by the Flinders Power assets.

SPS has an interest rate swap with a notional amount of \$25 million, converting variable rate debt to a fixed-rate. Young Gas Storage and Quixx Linden projects, which are unconsolidated equity investments of Xcel Energy, have interest rate swaps converting project debt from variable rate to fixed rate. These two amortizing swaps had a total notional amount of \$39.5 million on Dec. 31, 2000. The approximate termination cost of Xcel Energy's portion of these three swaps was \$4.5 million at Dec. 31, 2000.

Xcel Energy's regulated energy marketing operation uses a combination of energy futures and forward contracts, along with physical supply to hedge market risks in the energy market. At Dec. 31, 2000, the notional value of these contracts was approximately \$90.4 million. If these contracts had been terminated on Dec. 31, 2000, Xcel Energy would have realized a net gain of approximately \$18.7 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

NRG's Power Marketing subsidiary uses energy futures and forward contracts, along with physical supply, to hedge market risk in the energy market. At Dec. 31, 2000, the net notional amount of these contracts was approximately \$309.3 million. If the contracts had been terminated on Dec. 31, 2000, NRG would have received approximately \$52.8 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

e prime uses various financial instruments as hedging mechanisms against future energy-related contractual obligations. e prime had financial derivatives related to its retail business with a notional value of \$8.3 million at Dec. 31, 2000. If these contracts had been terminated at Dec. 31, 2000, e prime would have realized a net gain of \$3.9 million. In addition, e prime's wholesale portfolio had a net notional value of (\$0.5) million, based on a combination of physical and financial transactions. If these contracts had been terminated on Dec. 31, 2000, e prime would have received \$3.3 million from the counterparties. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

NRG had one foreign currency hedge outstanding at Dec. 31, 2000. The contract had a notional value of \$8.8 million and hedged expected cash flows from the Killingholme project in England. The currency hedge expired on Jan. 31, 2001. If the contract had been terminated on Dec. 31, 2000, NRG would have paid the counterparties \$0.7 million. Management believes the risk of counterparty nonperformance with regards to any of the hedging transactions is not significant.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. In addition, NRG uses letters of credit for nonregulated equity commitments, collateral for credit agreements, fuel purchase and operating commitments, and bids on development projects. At Dec. 31, 2000, there were \$113 million in letters of credit outstanding, including \$58 million related to NRG commitments. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

14. COMMITMENTS AND CONTINGENT LIABILITIES

Legislative Resource Commitments

In 1994, NSP-Minnesota received Minnesota legislative approval for additional on-site temporary spent fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Seventeen dry cask containers were approved. As of Dec. 31, 2000, NSP-Minnesota had loaded twelve casks. The Minnesota Legislature established several energy resource and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. These commitments can be met by building, purchasing, or in the case of biomass, converting generation resources.

The 1994 legislation requires NSP-Minnesota to have 425 megawatts of wind resources contracted by Dec. 31, 2002. Of this commitment, approximately 80 megawatts remain to be contracted. During 1999, the MPUC ordered an additional 400 megawatts to be contracted by 2012, subject to least-cost determinations. The 1994 legislation also requires NSP-Minnesota to contract for 125 megawatts of biomass-fueled energy, which has essentially been fulfilled.

Other commitments established by the Legislature include a discount for low-income electric customers, required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force. NSP-Minnesota has implemented programs to meet the legislative commitments. NSP-Minnesota's capital commitments include the known effects of the Prairie Island legislation. The impact of the legislation on future power purchase commitments and other operating expenses is not yet determinable.

Capital Commitments

As discussed in Liquidity and Capital under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2000, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately \$5.0 billion in 2001, \$3.0 billion in 2002 and \$3.3 billion in 2003.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission control equipment may impact actual capital requirements.

Xcel Energy's capital expenditures include approximately \$3.1 billion in 2001 for NRG investments and asset acquisitions. NRG's future capital requirements may vary significantly. For 2001, NRG's capital requirements reflect expected acquisitions of existing generation facilities, including the Conectiv fossil assets, North Valmy, LS Power, Clark gas-fired assets, Reid Gardner coal-fired assets and the Bridgeport and New Haven Harbor coal-fired facilities.

California Power Market

NRG operates in and sells to the wholesale power market in California. During the fourth quarter of 2000, the inability of certain California utilities to recover rising energy costs through regulated prices charged to retail customers created financial difficulties. The California utilities have appealed to state agencies and regulators for the opportunity to be reimbursed for costs incurred that are not currently recoverable through the existing rate structure. Absent such relief, some of the utilities have indicated they may be unable to continue to service their debt and/or otherwise pay obligations, or would consider discontinuing energy service to customers to avoid incurring costs that are not recoverable. Due to these circumstances, various bond rating agencies have lowered the credit rating of the California utilities to below investment grade. California state agencies and regulators, along with federal agencies such as the FERC have characterized the situation as a national emergency. Although

changes may be necessary in the California utility regulatory model to address the problem in the long run, in the short term the alternatives being discussed include financial support for distressed utilities to ensure continued energy service to California customers. However, at this time it is unknown whether or when such financial support will be made available to California utilities.

At Dec. 31, 2000, NRG had not yet collected approximately \$105 million in revenues from distressed utilities and the independent system operator in California, which are potentially at risk if financial relief or support is not provided. In addition, Xcel Energy's wholesale trading operation has a receivable from the California Independent System Operator for approximately \$3 million. Although there is uncertainty as to the final resolution of this matter, management believes that its revenue from California utilities and the independent system operator will ultimately be collected.

Tax Matters

PSR Investments, Inc. (PSRI), a subsidiary of PSCo, owns and manages permanent life insurance policies on certain past and present employees. The IRS has issued a Notice of Proposed Adjustment proposing to disallow interest expense related to corporate-owned life insurance (COLI) policy loans taken in tax years 1993-1997. The total disallowance of interest expense deductions for the five years as proposed by the IRS is approximately \$175 million. A request for technical advice from the IRS National Office with respect to the proposed adjustment is pending. In addition, interest expense deductions for the period 1998 through 2000 totals approximately \$168 million.

Management is vigorously contesting this issue. While the outcome of this matter cannot be predicted, management believes that PSRI's tax deduction of interest expense on life insurance policy loans was in full compliance with the tax law and believes that the resolution of this matter will not have a material adverse impact on Xcel Energy's financial position, results of operations or cash flows. For this reason, PSRI has not recorded any provision for income tax or interest expense related to this matter and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years.

Postemployment Benefits

PSCo adopted accrual accounting for postemployment benefits under SFAS No. 112—"Employers' Accounting for Postemployment Benefits" in 1994. The costs of these benefits were historically recorded on a pay-as-you-go basis and, accordingly, PSCo recorded regulatory assets in anticipation of obtaining future rate recovery of these costs. PSCo recovered its FERC jurisdictional portion of these costs. PSCo requested approval to recover its Colorado retail natural gas jurisdictional portion in a 1996 retail rate case and its retail electric jurisdictional portion in the electric earnings test filing for 1997. In the 1996 rate case, the CPUC allowed recovery of postemployment benefit costs on an accrual basis, but denied PSCo's request to amortize the regulatory asset. PSCo appealed this decision to the Denver District Court. In 1998, the CPUC deferred the final determination of the regulatory treatment of the electric jurisdictional costs pending the outcome of PSCo's appeals on the natural gas rate case. On Dec. 16, 1999, the Denver District Court affirmed the decision by the CPUC. On Jan. 31, 2000, PSCo filed a Notice of Appeal with the Colorado Supreme Court and expects a final decision on this matter during 2001. PSCo continues to believe that it will ultimately be allowed to recover this regulatory asset. If PSCo is unsuccessful in its appeal, all unrecoverable amounts totaling approximately \$23 million will be written off.

Conservation Incentive Recovery

In June 1999, the MPUC denied NSP-Minnesota recovery of 1998 lost margins, load management discounts and incentives associated with state-mandated programs for electric energy conservation. Xcel Energy recorded a \$35 million charge in 1999 based on this action. NSP-Minnesota appealed the MPUC decision and in December 2000, the Minnesota Court of Appeals reversed the MPUC decision.

In January 2001, the MPUC appealed the lower court decision to the Minnesota Supreme Court. On Feb. 23, 2001, the Minnesota Supreme Court declined to hear the MPUC's appeal. NSP-Minnesota

is awaiting an order from the MPUC regarding the implementation of the appeals court decision before adjusting any liabilities recorded for this matter. As of Dec. 31, 2000, NSP-Minnesota had recorded a liability of \$40 million, including carrying charges, for potential refunds to customers pending the final resolution of this matter.

Leases

Xcel Energy's subsidiaries lease various equipment and facilities used in the normal course of business, some of which are accounted for as capital leases. Expiration of the capital leases range from 2010 to 2029. The net book value of property under capital leases was approximately \$55 million and \$57 million at Dec. 31, 2000 and 1999, respectively. Assets acquired under capital leases are recorded as property at the lower of fair-market value or the present value of future lease payments and are amortized over their actual contract term in accordance with practices allowed by regulators. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

Rental expense under operating lease obligations was approximately \$56 million, \$57 million and \$49 million for 2000, 1999 and 1998, respectively. Future commitments under these leases generally decline from current levels.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$9.5 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured \$200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$9.3 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$88 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.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$1.5 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$3 million for business interruption insurance and \$11 million for property damage insurance if losses exceed accumulated reserve funds.

Fuel Contracts

Xcel Energy has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2001 and 2017. In total, Xcel Energy is committed to the minimum purchase of approximately \$2.1 billion of coal, \$13 million of nuclear fuel and \$706 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy'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 most fuel costs.

Purchase Power Agreements

The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost recovery mechanisms. Additionally, NSP-Minnesota, PSCo and SPS have long-term, purchased-power contracts with various regional utilities, expiring through 2025.

NSP-Minnesota has a 500-megawatt participation power purchase commitment with Manitoba Hydro, which expires in 2005. The cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota's Sherco 3 generating plant, adjusted to 1993 dollars. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro's system capacity and account for approximately 10 percent of NSP-Minnesota's 2000 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2000, the estimated future payments for capacity that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

	Other	Regional Utilities	Total
	(Thousands of dollars)		
2001	\$ 203,347	\$ 253,932	\$ 457,279
2002	225,031	241,358	466,389
2003	256,791	231,361	488,152
2004	255,185	221,907	477,092
2005 and thereafter	2,061,785	983,144	3,044,929
Total	<u>\$3,002,139</u>	<u>\$1,931,702</u>	<u>\$4,933,841</u>

For the past 37 years, Cheyenne has purchased all energy requirements from PacifiCorp. Cheyenne's full-requirements power purchase agreement with PacifiCorp expired in December 2000. During 2000, Cheyenne issued a request for proposal and conducted negotiations with PacifiCorp and other wholesale power suppliers. During 2000, as contract details for a new agreement were being finalized, supply conditions and market prices in the western United States dramatically changed. Cheyenne was unable to execute an agreement with PacifiCorp for the prices and terms Cheyenne had been negotiating. Additionally, PacifiCorp failed to provide the FERC and Cheyenne 60-days notice to terminate service, as required by the Federal Power Act. Cheyenne filed a complaint with the FERC, requesting that PacifiCorp continue providing service under the existing tariff through the 60-day notice period. On Feb. 7, 2001, the FERC issued an order requiring PacifiCorp to provide service under the terms of the old contract through Feb. 24, 2001.

Cheyenne has begun implementing the changes required to transition from a full-requirements customer to an operating utility as the best means of providing energy supply. In February 2001, PSCo filed an agreement with the FERC to provide a portion of Cheyenne's service. Cheyenne has also entered into agreements with other producers to meet both short-term and long-term energy supply needs and continues to negotiate with suppliers to meet its load requirements for the summer of 2001.

Total purchased power costs are projected to increase approximately \$80 million in 2001. Purchased power and natural gas costs are recoverable in Wyoming. Cheyenne is required to file applications with the WPSC for approval of adjustment mechanisms in advance of the proposed

effective date and demonstrate the reasonableness of the costs. Cheyenne expects to make its request for an electric cost adjustment increase in March 2001.

Environmental Contingencies

We are subject to regulations covering air and water quality, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the construction and operation of, and cost of building and operating, our facilities.

Site Remediation

We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2000, there were three categories of sites:

- Third-party sites, such as landfills, to which we are alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes;
- The site of a former federal uranium enrichment facility; and
- Sites of former manufactured gas plants (MGPs) operated by our subsidiaries or predecessors.

We record a liability when we have enough information to develop an estimate of the cost of remediating a site and revise the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, we may have to make assumptions where facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties and the identification of new environmental cleanup sites.

We revise our estimates as facts become known, but at Dec. 31, 2000, our liability for the cost of remediating sites for which an estimate was possible was \$54 million, including \$14 million in current liabilities.

Some of the cost of remediation may be recovered from others through:

- Insurance coverage;
- Recovery from other parties that have contributed to the contamination; and
- Recovery from customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. We have recorded estimates of our share of future costs for these sites. We are not aware of any other parties' inability to pay, nor do we know if responsibility for any of the sites is in dispute.

Federal Uranium Enrichment Facility

Approximately \$23 million of the long-term liability and \$4 million of the current liability relate to a DOE assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. 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 NSP-Minnesota's nuclear generating plants. See Note 15 to Financial Statements for further discussion of nuclear obligations.

MGP Sites

NSP-Wisconsin was named as one of three PRPs for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city, lakeshore park area and a small area of Lake Superior's Chequamegon Bay adjoining the park.

The Wisconsin Department of Natural Resources (WDNR) and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between \$4 million and \$93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR are expected to select the method of remediation to use at the site during late 2001 or early 2002. Until the EPA and the WDNR select a remediation strategy for all operable units at the site and determine the level of responsibility of each PRP, we are not able to accurately estimate our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, estimated using information available to date and using reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities.

We proposed, and the EPA and WDNR have approved, an interim action (a groundwater treatment system) for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to ultimate remediation cost of the entire site. It is probable that, even with outside funding, final remedial costs to be borne by NSP-Wisconsin will be material.

The MPUC allowed NSP-Minnesota to defer certain remediation costs of four active remediation sites in 1994. In September 1998, the MPUC allowed the recovery of these MGP site remediation costs in natural gas rates, with a portion assigned to NSP's electric operations for two sites formerly used by NSP generating facilities. Accordingly, NSP-Minnesota has recorded an environmental regulatory asset for these costs. NSP-Minnesota may request recovery of costs to remediate other activated sites following the completion of preliminary investigations.

Other

Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

In January 1996, in a lawsuit by PSCo against its insurance providers, the Denver District Court entered final judgment in favor of PSCo in the amount of \$5.6 million for certain cleanup costs at the Barter site in central Denver. In September 1999, the Colorado Supreme Court held that the trial court should have allocated the damages and self-insured retentions over the entire period the facilities were in operation. Although the Colorado Supreme Court remanded the judgement to the trial court for additional proceedings, it suggested that its ruling may reduce PSCo's available recovery to approximately \$1.4 million. PSCo requested recovery of environmental costs of approximately

\$7.7 million related to Barter over four years in its proposed Performance-Based Regulatory Plan for calendar years 1998-2001.

Plant Emissions

In 1996, a conservation organization filed a complaint in the U.S. District Court pursuant to provisions of the Clean Air Act against the joint owners of the Craig Steam Electric Generating Station, located in western Colorado. Tri-State Generation and Transmission Association, Inc. is the operator of the Craig station and PSCo owns an undivided interest in each of two units at the station, totaling approximately 9.7 percent. In October 2000, the parties, the EPA and the Colorado Department of Public Health and Environment (CDPHE) reached an agreement in principle resolving all air-quality matters related to the facility. The final agreement was negotiated during the fourth quarter of 2000 and was filed with the court on Jan. 10, 2001. The final agreement requires the installation of additional emission control equipment at a cost of approximately \$105 million (based on an estimate from Tri-State). The equipment will be installed over a period of several years. In addition, the settlement requires the defendants collectively to pay a civil penalty of \$500,000 and to contribute \$1.5 million to fund conservation activities. The contribution to conservation activities will be refunded if the plant achieves a specified level of emissions control. The agreement will become enforceable after a period for public comment and approval by the court.

In October 2000, the EPA found that NSP-Wisconsin's French Island electric generating plant should be classified as a "large municipal waste combustor" under Section 129 of the Clean Air Act. This letter was contrary to a 1997 EPA letter in which it had found that French Island should be classified as a "small combustor." The large combustor emission limits became enforceable in December 2000. NSP-Wisconsin is attempting to work with the EPA to resolve the dispute regarding the status of the French Island plant. If a resolution is finalized, it may require, among other things, the installation of additional emission controls on the plant.

NRG also owns electric generating plants throughout the United States. These plants are subject to federal and state emission standards and other environmental regulations. NRG continues to study and investigate the methods and costs of complying with these standards and regulations. Although the future financial effect is not yet known, it may be material.

The Commonwealth of Massachusetts is seeking additional emissions reductions beyond current requirements. The Massachusetts Department of Environmental Protection (MDEP) has issued proposed regulations that would require significant emissions reductions from certain coal-fired power plants in the state, including NRG's Somerset facility. The MDEP has proposed that such facilities comply with stringent limits on emissions of NO_x by December 2003; on emissions of SO₂ commencing in December 2003, with further reductions required by December 2005; and on emissions of CO₂ by December 2005. In addition to output-based limits (a standard which limits emissions to a certain rate per net megawatt-hour), the proposed regulations also would limit, by December 2003, the total emissions of nitrogen oxides and sulfur dioxide at the Somerset facility to no more than 75 percent of the average annual emissions of the Somerset facility for the years 1997 through 1999. Finally, the proposed regulations require the MDEP to evaluate, by December 2002, the technological and economic feasibility of controlling or eliminating mercury emissions by the year 2010, and to propose mercury emission standards within 18 months of completion of the feasibility evaluation. Compliance with these proposed regulations, if such regulations become effective, could have a material impact on the operation of NRG's Somerset facility. The annual average carbon dioxide emission rate identified in the proposed regulations cannot be met by the Somerset facility.

Legal Claims

In the normal course of business, Xcel Energy is a party to routine claims and litigation arising from prior and current operations. Xcel Energy is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition.

On Dec. 11, 1998, a natural gas explosion in St. Cloud, Minn., killed four people, including two NSP-Minnesota employees, injured approximately 14 people and damaged several buildings. The accident occurred as a crew from Cable Constructors Inc. (CCI) was installing fiber optic cable for Seren. Seren, CCI and Sirti, an architecture/engineering firm retained by Seren, are named as defendants in 22 lawsuits relating to the explosion. NSP-Minnesota is a defendant in 19 of the lawsuits. NSP-Minnesota and Seren deny any liability for this accident. On July 11, 2000, the National Transportation Safety Board issued a report, which determined that CCI's inadequate installation procedures and delay in reporting the natural gas hit were the proximate cause of the accident. NSP-Minnesota has a self-insured retention deductible of \$2 million with general liability coverage limits of \$185 million. Seren's primary insurance coverage is \$1 million and its secondary insurance coverage is \$185 million. The ultimate cost to Xcel Energy, NSP-Minnesota and Seren, if any, is presently unknown.

On or about July 12, 1999, Fortistar Capital, Inc. commenced an action against NRG in Hennepin County (Minnesota) District Court, seeking damages in excess of \$100 million and an order restraining NRG from consummating the acquisition of Niagara Mohawk Power Corp.'s Oswego generating station. Fortistar's motion for a temporary restraining order was denied. A temporary injunction hearing was held on Sept. 27, 1999. The acquisition was consummated in October 1999. On Jan. 14, 2000, the court denied Fortistar's request for a temporary injunction. In April and December 2000, NRG filed summary judgment motions to dispose of the litigation respecting both liability and damages, and a hearing on these motions was held on Jan. 26, 2001. No ruling on the motions has been received to date. A trial date has been scheduled for April 2001. NRG has asserted numerous counterclaims against Fortistar and will continue to vigorously defend the suit.

NRG and other power generators and power traders have been named as defendants in certain private plaintiff class actions filed in the Superior Court of the State of California for the County of San Diego in San Diego, California, on Nov. 27, 2000, and Nov. 29, 2000, and in the Superior Court of the State of California, City and County of San Francisco filed Jan. 24, 2001. NRG and other power generators and power traders have also been named in another suit filed on Jan. 16, 2001, in the Superior Court of the State of California for the County of San Diego, brought by three California water districts, as consumers of electricity and in a suit filed on Jan. 18, 2001, in Superior Court of the State of California, County of San Francisco, brought by the San Francisco City Attorney on behalf of the People of the State of California. Xcel Energy and Northern States Power Company were also named as defendants in the litigation commenced in San Francisco because of their relationship with NRG. Although the complaints contain a number of allegations, the basic claim is that, by underbidding forward contracts and exporting electricity to surrounding markets, the defendants, acting in collusion, were able to drive up wholesale prices on the Real Time and Replacement Reserve markets, through the Western Systems Coordinating Council and otherwise. The complaints allege that the conduct violated California antitrust and unfair competition laws. NRG does not believe that it has engaged in any illegal activities and intends to vigorously defend these lawsuits.

On Feb. 3, 2000, Dynege Engineering Inc. filed a lawsuit against Utility Engineering (UE), a wholly owned subsidiary of Xcel Energy, in Harris County, Texas. In its lawsuit, Dynege claims it is entitled to recover approximately \$9.7 million for damages allegedly caused by UE's late and deficient engineering services performed for the Rocky Road electrical generating plant in Dundee, Ill. UE denies the merits of Dynege's lawsuit. UE also maintains that it is insured against this claim pursuant to its professional liability policy. UE's self-insured retention under this policy is \$1 million.

15. NUCLEAR OBLIGATIONS

Fuel Disposal

NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP's nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour

sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately \$12 million in 2000, \$12 million in 1999 and \$11 million in 1998. In total, NSP-Minnesota had paid approximately \$284 million to the DOE through Dec. 31, 2000. However, we cannot determine whether 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 Nuclear Waste Policy Act required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. In 1996, the DOE notified commercial spent fuel owners of an anticipated delay in accepting spent nuclear fuel by the required date and conceded that a permanent storage or disposal facility will not be available until at least 2010. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE's failure to meet its statutory and contractual obligations.

NSP-Minnesota has its own temporary on-site storage facilities at its Monticello and Prairie Island nuclear plants. With the dry cask storage facilities approved in 1994, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least 2007. 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. We are investigating alternatives for spent fuel storage until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities. If on-site temporary storage at Prairie Island reaches approved capacity, we could seek interim storage at this or another contracted private facility, if available.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE's uranium enrichment facilities. In 1993, NSP-Minnesota recorded the DOE's initial assessment of \$46 million, which is payable in annual installments from 1993-2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2000 was \$4 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, we deferred the unamortized assessment of \$28 million at Dec. 31, 2000, as a regulatory asset.

Plant Decommissioning

Decommissioning of NSP-Minnesota's nuclear facilities is planned for the years 2010-2022, using the prompt dismantlement method. We are 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. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy's financial statements.

The FASB has proposed new accounting standards that, if approved, would require the full accrual of nuclear plant decommissioning and other site exit obligations no sooner than 2002. Using Dec. 31, 2000, estimates, adoption of the proposed accounting would result in the recording of the total discounted decommissioning obligation of \$838 million as a liability, with the corresponding costs capitalized as plant and other assets and depreciated over the operating life of the plant. We have not yet determined the potential impact of the FASB's proposed changes in the accounting for site exit obligations, such as costs of removal, other than nuclear decommissioning. However, the ultimate decommissioning and site exit costs to be accrued are expected to be similar to the current methodology. 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, we record 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. 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 an assumed rate

of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding.

The MPUC last approved NSP-Minnesota's nuclear decommissioning study and related nuclear plant depreciation capital recovery request in April 2000, using 1999 cost data. Although we expect to operate Prairie Island through the end of each unit's licensed life, the approved capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2007. This is about seven years earlier than each unit's licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding used fuel storage. We believe future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2000, primarily consisted of investments in fixed-income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in 1 to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

At Dec. 31, 2000, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of \$583 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation at Dec. 31, 2000:

	<u>2000</u>
	(Thousands of dollars)
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	\$ 958,266
Effect of escalating costs to 2000 dollars (at 4.5 percent per year)	41,685
Estimated decommissioning cost obligation in current dollars	999,951
Effect of escalating costs to payment date (at 4.5 percent per year)	894,322
Estimated future decommissioning costs (undiscounted)	1,894,273
Effect of discounting obligation (using risk-free interest rate)	(1,056,360)
Discounted decommissioning cost obligation	837,913
Assets held in external decommissioning trust	563,812
Discounted decommissioning obligation in excess of assets currently held in external trust	<u>\$ 274,101</u>

Decommissioning expenses recognized include the following components:

	<u>2000</u>	<u>1999</u>	<u>1998</u>
	(Thousands of dollars)		
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	\$ 51,433	\$33,178	\$33,178
Internally funded (including interest costs)	(16,111)	1,595	1,477
Interest cost on externally funded decommissioning obligation	5,151	4,191	6,960
Earnings from external trust funds	(5,151)	(4,191)	(6,960)
Net decommissioning accruals recorded	<u>\$ 35,322</u>	<u>\$34,773</u>	<u>\$34,655</u>

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 deductions on the income statement.

16. REGULATORY ASSETS AND LIABILITIES

Our regulated businesses prepare their financial statements in accordance with the provisions of SFAS 71, as discussed in Note 1 to the Financial Statements. Under SFAS 71, regulatory assets and liabilities can be created for amounts that regulators may allow us to collect, or may require us to pay back to customers in future electric and natural gas rates.

SFAS 71 accounting cannot be used by any portion of our business that is not regulated. Efforts to restructure and deregulate the utility industry have already ended our ability to apply SFAS 71 to the generation business of SPS and may further reduce or end our ability to apply SFAS 71 in the future. Write-offs and material changes to our balance sheet, income and cash flows may result.

Restructuring legislation was enacted in the SPS jurisdictions of Texas and New Mexico. See Note 12 to the Financial Statements. When the final PUCT restructuring order was issued in May 2000, SPS discontinued using SFAS 71 accounting for its electric generation business. In the second quarter of 2000, SPS' generation-related regulatory assets and other deferred costs were written off. SPS' electric transmission and distribution businesses continue to meet the requirements of SFAS 71 and are expected to remain regulated.

The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

	Remaining Amortization Period	2000	1999
(Thousands of dollars)			
AFDC recorded in plant*	Plant Lives	\$159,406	\$184,860
Conservation programs*	Up to 5 Years	52,444	40,868
Losses on reacquired debt	Term of Related Debt	85,688	84,190
Environmental costs	Primarily 9 Years	47,595	48,708
Unrecovered gas costs**	1-2 Years	24,719	15,266
Deferred income tax adjustments	Mainly Plant Lives		28,581
Nuclear decommissioning costs	5 Years	54,267	63,835
Employees' postretirement benefits other than pension	12 Years	46,680	53,321
Employees' postemployment benefits	Undetermined	23,223	23,374
Renewable development costs	Undetermined	10,500	
State commission accounting adjustments*	Plant Lives	7,614	7,641
Other	Various	12,125	16,083
Total regulatory assets		<u>\$524,261</u>	<u>\$566,727</u>
Investment tax credit deferrals		\$119,060	\$136,349
Unrealized gains from decommissioning investments		171,736	177,578
Pension costs-regulatory differences		139,178	84,198
Conservation incentives		40,679	25,284
Deferred income tax adjustments		12,416	
Fuel costs, refunds and other		11,497	18,795
Total regulatory liabilities		<u>\$494,566</u>	<u>\$442,204</u>

* Earns a return on investment in the ratemaking process.

** Excludes current portion with expected rate recovery within 12 months of \$13 million and \$8 million for 2000 and 1999, respectively. In addition, excludes other deferred energy costs also recoverable within 12 months of \$270 million and \$47 million for 2000 and 1999, respectively.

17. CAJUN PRO FORMA RESULTS

During March 2000, NRG completed the acquisition of two fossil-fueled generating plants from Cajun Electric Power Cooperative, Inc., for approximately \$1 billion. The following information summarizes the pro forma results of operations as if the acquisition, which was accounted for as a purchase, had occurred as of the beginning of the respective periods for which pro forma information is presented. The preacquisition period information is not necessarily comparable to the postacquisition period information.

	Actual Results	
	2000	1999
	(Millions of dollars, except earnings per share)	
Revenue	\$11,592	\$7,816
Net income	527	571
Earnings available for common shareholders	523	566
Total earnings per share	\$ 1.54	\$ 1.70
	Pro Forma Results (unaudited)	
	2000	1999
	(Millions of dollars, except earnings per share)	
Revenue	\$11,672	\$8,184
Net income	523	574
Earnings available for common shareholders	519	569
Total earnings per share	\$ 1.54	\$ 1.71

18. SEGMENT AND RELATED INFORMATION

Xcel Energy has five reportable segments: Electric Utility, Gas Utility and three of its nonregulated energy businesses, NRG, Xcel International and e prime, all subsidiaries of Xcel Energy.

- Xcel Energy's Electric Utility generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, New Mexico, Wyoming, Kansas and Oklahoma. It also makes sales for resale and provides wholesale transmission service to various entities in the United States. Electric Utility also includes electric trading.
- Xcel Energy's Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan, Arizona, Colorado and Wyoming.
- NRG develops, builds, acquires, owns and operates several nonregulated energy-related businesses, including independent power production, commercial and industrial heating and cooling, and energy-related refuse-derived fuel production, both domestically and outside the United States.
- Xcel Energy International's most significant holding is Yorkshire Power, a joint venture equally owned by Xcel Energy International and a subsidiary of American Electric Power Co. Yorkshire's main business is the distribution and supply of electricity and the supply of natural gas in the United Kingdom.
- e prime trades and markets natural gas throughout the United States.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include a company

involved in nonregulated power and natural gas marketing activities throughout the United States; a company that invests in and develops cogeneration and energy-related projects; a company that is engaged in engineering, design construction management and other miscellaneous services; a company engaged in energy consulting, energy efficiency management, conservation programs and mass market services; an affordable housing investment company; a broadband telecommunications company; and several other small companies and businesses.

To report net income for electric and natural gas utility segments, Xcel Energy must assign or allocate all costs and certain other income. In general, costs are:

- Directly assigned wherever applicable;
- Allocated based on cost causation allocators wherever applicable; and
- Allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

Business Segments

	Electric Utility	Gas Utility	NRG	Xcel Energy International	e prime	All Other	Reconciling Eliminations	Consolidated Total
(Thousands of dollars)								
2000								
Operating revenues from								
external customers*	\$6,492,194	\$1,466,478	\$2,014,757		\$1,269,506	\$162,566		\$11,405,501
Intersegment revenues	1,179	5,761	2,256		53,928	78,419	(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates			142,086	35,327	1,203	4,098		182,714
Total revenues	<u>\$6,493,373</u>	<u>\$1,472,239</u>	<u>\$2,159,099</u>	<u>\$ 35,327</u>	<u>\$1,324,637</u>	<u>\$245,083</u>	<u>\$(137,962)</u>	<u>\$11,591,796</u>
Depreciation and amortization	574,018	85,353	123,404	178	569	8,873		792,395
Financing costs, mainly								
interest expense	333,512	60,755	295,917	7,887	200	57,614	(59,780)	696,105
Income tax expense (credit)	261,942	36,962	92,474	(604)	(3,995)	(81,914)		304,865
Segment income (loss) before extraordinary items	\$ 340,634	\$ 57,911	\$ 182,935	\$ 29,325	\$ (6,158)	\$(43,250)	\$ (15,609)	\$ 545,788
Extraordinary items, net of tax	(18,960)							(18,960)
Segment net income (loss)	<u>\$ 321,674</u>	<u>\$ 57,911</u>	<u>\$ 182,935</u>	<u>\$ 29,325</u>	<u>\$ (6,158)</u>	<u>\$(43,250)</u>	<u>\$ (15,609)</u>	<u>\$ 526,828</u>

	Electric Utility	Gas Utility	NRG	Xcel Energy International	e prime	All Other	Reconciling Eliminations	Consolidated Total
(Thousands of dollars)								
1999								
Operating revenues from								
external customers*	\$5,454,958	\$1,141,294	\$ 427,567		\$ 564,045	\$114,587		\$ 7,702,451
Intersegment revenues	1,303	11,785	963		2,102	119,546	(134,731)	968
Equity in earnings (losses) of unconsolidated affiliates			68,947	44,908	1,467	(3,198)		112,124
Total revenues	<u>\$5,456,261</u>	<u>\$1,153,079</u>	<u>\$ 497,477</u>	<u>\$ 44,908</u>	<u>\$ 567,614</u>	<u>\$230,935</u>	<u>\$(134,731)</u>	<u>\$ 7,815,543</u>
Depreciation and amortization	546,794	82,206	37,026	182	3,762	14,005		683,975
Financing costs, mainly								
interest expense	300,108	53,217	92,570	714	226	25,262	(19,020)	453,077
Income tax expense (credit)	272,129	24,081	(26,416)	(13,559)	(2,984)	(59,443)	(14,135)	179,673
Segment net income (loss)	<u>\$ 431,510</u>	<u>\$ 49,175</u>	<u>\$ 57,195</u>	<u>\$ 58,301</u>	<u>\$ (4,765)</u>	<u>\$(7,362)</u>	<u>\$ (13,121)</u>	<u>\$ 570,933</u>

	Electric Utility	Gas Utility	NRG	Xcel Energy International	e prime	All Other	Reconciling Eliminations	Consolidated Total
(Thousands of dollars)								
1998								
Operating revenues from								
external customers*	\$5,057,936	\$1,109,953	\$ 98,688		\$ 181,992	\$162,813		\$ 6,611,382
Intersegment revenues	1,131	14,573	1,737			75,209	(91,722)	928
Equity in earnings (losses) of unconsolidated affiliates			81,706	38,127	1,504	(5,352)		115,985
Total revenues	<u>\$5,059,067</u>	<u>\$1,124,526</u>	<u>\$ 182,131</u>	<u>\$ 38,127</u>	<u>\$ 183,496</u>	<u>\$232,670</u>	<u>\$(91,722)</u>	<u>\$ 6,728,295</u>
Depreciation and amortization	524,703	75,753	16,320	121	3,438	10,915		631,250
Financing costs, mainly								
interest expense	262,654	44,074	50,313	745	675	18,960	5,865	383,286
Income tax expense (credit)	300,103	24,945	(25,654)	(15,817)	(1,987)	(26,225)	(14,974)	240,391
Segment net income (loss)	<u>\$ 505,077</u>	<u>\$ 47,180</u>	<u>\$ 41,732</u>	<u>\$ 51,978</u>	<u>\$ (3,256)</u>	<u>\$ 9,621</u>	<u>\$ (28,002)</u>	<u>\$ 624,330</u>

* All operating revenues are from external customers located in the United States except \$290 million of NRG operating revenues in 2000, which came from external customers outside of the United States. However, Xcel Energy International and NRG also have significant equity investments for nonregulated projects outside the United States. NRG's equity in earnings of unconsolidated affiliates, primarily independent power projects, includes \$19.2 million in 2000, \$38.6 million in 1999 and \$29.3 million in 1998 from nonregulated projects located outside of the United States. NRG's equity investments in projects outside of the United States were \$566 million in 2000, \$606 million in 1999 and \$557 million in 1998. All of Xcel Energy International's equity in earnings of unconsolidated affiliates is from outside of the United States. Xcel Energy International's equity investments and projects outside of the United States were \$383 million in 2000, \$367 million in 1999 and \$333 million in 1998. In addition, NRG's wholly owned foreign assets (\$796 million in 2000) contributed earnings of \$30.1 million in 2000 and \$0 in 1999 and 1998.

ITEM 9—CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

During 2000, there were no disagreements with Xcel Energy's independent public accountants on accounting procedures or accounting and financial disclosures. As discussed in Xcel Energy's Form 8-K filed on Aug. 21, 2000, in connection with the merger, Xcel Energy's management informed PricewaterhouseCoopers LLP that the firm would no longer be engaged as principal independent accountants for the Registrant. On Aug. 18, 2000, the Audit Committee of Xcel Energy's Board of Directors recommended, and the Xcel Energy Board approved, the decision to engage Arthur Andersen LLP as its new principal independent accountants for the Registrant for 2000.

PART III

ITEM 10—DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information required under this Item with respect to directors is set forth in the Registrant's 2001 Proxy Statement for its Annual Meeting of Shareholders to be held April 25, 2001, under the caption "Election of Directors," which is incorporated by reference. Information with respect to Executive Officers is include in Item 1 to this report.

ITEM 11—EXECUTIVE COMPENSATION

Information required under this Item is set forth in the Registrant's 2001 Proxy Statement for its Annual Meeting of Shareholders to be held April 25, 2001, under the caption "Compensation of Executive Officers," which is incorporated by reference.

ITEM 12—SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information concerning the security ownership of the directors and officers of Xcel Energy is contained under the caption "Share Ownership of Directors, Nominees, and Named Executive Officers" in the Xcel Energy 2001 Proxy Statement for its Annual Meeting of Shareholders to be held April 25, 2001, which is incorporated by reference.

ITEM 13—CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information concerning relationships and related transactions of the directors and officers of Xcel Energy is contained in the Xcel Energy 2001 Proxy Statement for its Annual Meeting of Shareholders to be held April 25, 2001, which is incorporated by reference.

ITEM 14—EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1.	<i>Financial Statements and Schedules</i>	<u>Page</u>
	Included in Part II of this report:	
	Report of Independent Accountants for the years ended Dec. 31, 2000, 1999, and 1998.	49
	Statements of Income for the three years ended Dec. 31, 2000.	50
	Statements of Cash Flows for the three years ended Dec. 31, 2000.	51
	Balance Sheets, Dec. 31, 2000 and 1999.	52
	Notes to Financial Statements.	57
2.	<i>Exhibits</i>	
	* Indicates incorporation by reference	
	+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors	

Xcel Energy

- 2.01* Agreement and Plan of Merger, dated as of March 24, 1999, by and between Northern States Power Company and New Century Energies, Inc. (Incorporated by reference to Exhibit 2.1 to the Report on Form 8-K (File No. 1-12907) of New Century Energies, Inc. dated March 24, 1999.)
- 3.01* Articles of Incorporation and Amendments of the Company (Filed as Exhibit 4.01 to the Company's Form 8-K (file no. 1-3034) filed on August 21, 2000).
- 3.02* By-Laws of the Company (Filed as Exhibit 4.3 to the Company's Registration Statement on Form S-8 (file no. 333-48590) filed on October 25, 2000).
- 4.01* Trust Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Filed as Exhibit 4.01 to the Company's Form 8-K Report (File No. 1-3034) dated Dec. 18, 2000).
- 4.02* Supplemental Trust Indenture dated Dec. 15, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee, creating \$600,000,000 principal amount of 7% Senior Notes, Series due 2010. (Filed as Exhibit 4.01 to the Company's Form 8-K Report (File No. 1-3034) dated Dec. 18, 2000).

NSP-Minnesota

- 4.03* Trust Indenture, dated Feb. 1, 1937, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit B-7 to File No. 2-5290.)
 - 4.04* Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit 4.02 to Form 10-K of NSP for the year 1988, File No. 1-3034.)
- Supplemental Indenture between NSP and said Trustee, supplemental to Exhibit 4.03, dated as follows:
- 4.05* June 1, 1942 (Exhibit B-8 to File No. 2-97667).
 - 4.06* Feb. 1, 1944 (Exhibit B-9 to File No. 2-5290).
 - 4.07* Oct. 1, 1945 (Exhibit 7.09 to File No. 2-5924).

4.08* July 1, 1948 (Exhibit 7.05 to File No. 2-7549).
4.09* Aug. 1, 1949 (Exhibit 7.06 to File No. 2-8047).
4.10* June 1, 1952 (Exhibit 4.08 to File No. 2-9631).
4.11* Oct. 1, 1954 (Exhibit 4.10 to File No. 2-12216).
4.12* Sept. 1, 1956 (Exhibit 2.09 to File No. 2-13463).
4.13* Aug. 1, 1957 (Exhibit 2.10 to File No. 2-14156).
4.14* July 1, 1958 (Exhibit 4.12 to File No. 2-15220).
4.15* Dec. 1, 1960 (Exhibit 2.12 to File No. 2-18355).
4.16* Aug. 1, 1961 (Exhibit 2.13 to File No. 2-20282).
4.17* June 1, 1962 (Exhibit 2.14 to File No. 2-21601).
4.18* Sept. 1, 1963 (Exhibit 4.16 to File No. 2-22476).
4.19* Aug. 1, 1966 (Exhibit 2.16 to File No. 2-26338).
4.20* June 1, 1967 (Exhibit 2.17 to File No. 2-27117).
4.21* Oct. 1, 1967 (Exhibit 2.01R to File No. 2-28447).
4.22* May 1, 1968 (Exhibit 2.01S to File No. 2-34250).
4.23* Oct. 1, 1969 (Exhibit 2.01T to File No. 2-36693).
4.24* Feb. 1, 1971 (Exhibit 2.01U to File No. 2-39144).
4.25* May 1, 1971 (Exhibit 2.01V to File No. 2-39815).
4.26* Feb. 1, 1972 (Exhibit 2.01W to File No. 2-42598).
4.27* Jan. 1, 1973 (Exhibit 2.01X to File No. 2-46434).
4.28* Jan. 1, 1974 (Exhibit 2.01Y to File No. 2-53235).
4.29* Sept. 1, 1974 (Exhibit 2.01Z to File No. 2-53235).
4.30* April 1, 1975 (Exhibit 4.01AA to File No. 2-71259).
4.31* May 1, 1975 (Exhibit 4.01BB to File No. 2-71259).
4.32* March 1, 1976 (Exhibit 4.01CC to File No. 2-71259).
4.33* June 1, 1981 (Exhibit 4.01DD to File No. 2-71259).
4.34* Dec. 1, 1981 (Exhibit 4.01EE to File No. 2-83364).
4.35* May 1, 1983 (Exhibit 4.01FF to File No. 2-97667).
4.36* Dec. 1, 1983 (Exhibit 4.01GG to File No. 2-97667).
4.37* Sept. 1, 1984 (Exhibit 4.01HH to File No. 2-97667).
4.38* Dec. 1, 1984 (Exhibit 4.01II to File No. 2-97667).
4.39* May 1, 1985 (Exhibit 4.36 to Form 10-K for the year 1985, File No. 1-3034).
4.40* Sept. 1, 1985 (Exhibit 4.37 to Form 10-K for the year 1985, File No. 1-3034).
4.41* July 1, 1989 (Exhibit 4.01 to Form 8-K dated July 7, 1989, File No. 1-3034).
4.42* June 1, 1990 (Exhibit 4.01 to Form 8-K dated June 1, 1990, File No. 1-3034).

- 4.43* Oct. 1, 1992 (Exhibit 4.01 to Form 8-K dated Oct. 13, 1992, File No. 1-3034).
- 4.44* April 1, 1993 (Exhibit 4.01 to Form 8-K dated March 30, 1993, File No. 1-3034).
- 4.45* Dec. 1, 1993 (Exhibit 4.01 to Form 8-K dated Dec. 7, 1993, File No. 1-3034).
- 4.46* Feb. 1, 1994 (Exhibit 4.01 to Form 8-K dated Feb. 10, 1994, File No. 1-3034).
- 4.47* Oct. 1, 1994 (Exhibit 4.01 to Form 8-K dated Oct. 5, 1994, File No. 1-3034).
- 4.48* June 1, 1995 (Exhibit 4.01 to Form 8-K dated June 28, 1995, File No. 1-3034).
- 4.49* April 1, 1997 (Exhibit 4.47 to Form 10-K for the year 1997, File No. 1-3034).
- 4.50* March 1, 1998 (Exhibit 4.01 to Form 8-K dated March 11, 1998, File No. 1-3034).
- 4.51* May 1, 1999 (Exhibit 4.49 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.52* June 1, 2000 (Exhibit 4.50 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.53* Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.54* Subordinated Debt Securities Indenture, dated as of Jan. 30, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee. (Exhibit 4.02 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.55* Preferred Securities Guarantee Agreement, dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.05 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.56* Preferred Securities Guarantee Agreement, dated as of Aug. 18, 2000, between Northern States Power Company and Wilmington Trust Company, as Trustee. (Exhibit 4.54 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.57* Amended and Restated Declaration of Trust of NSP Financing I, dated as of Jan. 31, 1997, including form of Preferred Security. (Exhibit 4.10 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.58* Supplemental Indenture, dated as of Jan. 31, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee, including form of Junior Subordinated Debenture. (Exhibit 4.12 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.59* Supplemental Trust Indenture dated Aug. 18, 2000 between Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.57 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.60* Common Securities Guarantee Agreement dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.13 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.61* Common Securities Guarantee Agreement dated as of Aug. 18, 2000, between NSP and Wilmington Trust Company, as Trustee. (Exhibit 4.59 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 4.62* Subscription Agreement, dated as of Jan. 28, 1997, between NSP Financing I and NSP. (Exhibit 4.14 to Form 8-K dated Jan. 28, 1997, File No. 001-03034.)
- 4.63* Trust Indenture, dated July 1, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K dated July 21, 1999, File No. 1-3034.)

- 4.64* Supplemental Trust Indenture, dated July 15, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to Form 8-K dated July 21, 1999, File No. 1-03034.)
- 4.65* Supplemental Trust Indenture, dated Aug. 18, 2000, among Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.63 to Form 10 of NSP-Minnesota, File No. 000-31709)

NSP-Wisconsin

- 4.66* Copy of Trust Indenture, dated April 1, 1947, From NSP-Wisconsin to Firststar Trust Company (formerly First Wisconsin Trust Company). (Filed as Exhibit 7.01 to Registration Statement 2-6982)
- 4.67* Copy of Supplemental Trust Indenture, dated March 1, 1949. (Filed as Exhibit 7.02 to Registration Statement 2-7825)
- 4.68* Copy of Supplemental Trust Indenture, dated June 1, 1957. (Filed as Exhibit 2.13 to Registration Statement 2-13463)
- 4.69* Copy of Supplemental Trust Indenture, dated Aug. 1, 1964. (Filed as Exhibit 4.20 to Registration Statement 2-23726)
- 4.70* Copy of Supplemental Trust Indenture, dated Dec. 1, 1969. (Filed as Exhibit 2.03E to Registration Statement 2-36693)
- 4.71* Copy of Supplemental Trust Indenture, dated Sept. 1, 1973. (Filed as Exhibit 2.03F to Registration Statement 2-49757)
- 4.72* Copy of Supplemental Trust Indenture, dated Feb. 1, 1982. (Filed as Exhibit 4.01G to Registration Statement 2-76146)
- 4.73* Copy of Supplemental Trust Indenture, dated March 1, 1982. (Filed as Exhibit 4.08 to Form 10-K Report 10-3140 for the year 1982)
- 4.74* Copy of Supplemental Trust Indenture, dated June 1, 1986. (Filed as Exhibit 4.09 to Form 10-K Report 10-3140 for the year 1986)
- 4.75* Copy of Supplemental Trust Indenture, dated March 1, 1988. (Filed as Exhibit 4.10 to Form 10-K Report 10-3140 for the year 1988)
- 4.76* Copy of Supplemental and Restated Trust Indenture, dated March 1, 1991. (Filed as Exhibit 4.01K to Registration Statement 33-39831)
- 4.77* Copy of Supplemental Trust Indenture, dated April 1, 1991. (Filed as Exhibit 4.01 to Form 10-Q Report 10-3140 for the quarter ended March 31, 1991)
- 4.78* Copy of Supplemental Trust Indenture, dated March 1, 1993. (Filed as Exhibit to Form 8-K Report 10-3140 dated March 3, 1993)
- 4.79* Copy of Supplemental Trust Indenture, dated Oct. 1, 1993. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Sept. 21, 1993)
- 4.80* Copy of Supplemental Trust Indenture, dated Dec. 1, 1996. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Dec. 12, 1996)
- 4.81* Trust Indenture dated September 1, 2000, between Northern States Power Company and Firststar Bank, N.A. as Trustee. (Filed as Exhibit 4.01 to Form 8-K 10-3140 dated Sept. 25, 2000)

4.82* Supplemental Trust Indenture dated September 15, 2000, between Northern States Power Company and Firststar Bank, N.A. as Trustee, creating \$80,000,000 principal amount of 7.64% Senior Notes, Series due 2008. (Filed as Exhibit 4.02 to Form 8-K 10-3140 dated Sept. 25, 2000)

PSCo

4.83* Indenture, dated as of Dec. 1, 1939, providing for the issuance of First Mortgage Bonds (Form 10 for 1946- Exhibit (B-1)).

4.84* Indentures supplemental to Indenture dated as of Dec. 1, 1939:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.	Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Mar. 14, 1941	10, 1946	B-2	Sept. 1, 1970	8-K, Sept. 1970	2
May 14, 1941	10, 1946	B-3	Feb. 1, 1971	8-K, Feb. 1971	2
Apr. 28, 1942	10, 1946	B-4	Aug. 1, 1972	8-K, Aug. 1972	2
Apr. 14, 1943	10, 1946	B-5	June 1, 1973	8-K, June 1973	1
Apr. 27, 1944	10, 1946	B-6	Mar. 1, 1974	8-K, Apr. 1974	2
Apr. 18, 1945	10, 1946	B-7	Dec. 1, 1974	8-K, Dec. 1974	1
Apr. 23, 1946	10-K, 1946	B-8	Oct. 1, 1975	S-7, (2-60082)	2(b)(3)
Apr. 9, 1947	10-K, 1946	B-9	Apr. 28, 1976	S-7, (2-60082)	2(b)(4)
June 1, 1947	S-1, (2-7075)	7(b)	Apr. 28, 1977	S-7, (2-60082)	2(b)(5)
Apr. 1, 1948	S-1, (2-7671)	7(b)(1)	Nov. 1, 1977	S-7, (2-62415)	2(b)(3)
May 20, 1948	S-1, (2-7671)	7(b)(2)	Apr. 28, 1978	S-7, (2-62415)	2(b)(4)
Oct. 1, 1948	10-K, 1948	4	Oct. 1, 1978	10-K, 1978	D(1)
Apr. 20, 1949	10-K, 1949	1	Oct. 1, 1979	S-7, (2-66484)	2(b)(3)
Apr. 24, 1950	8-K, Apr. 1950	1	Mar. 1, 1980	10-K, 1980	4(c)
Apr. 18, 1951	8-K, Apr. 1951	1	Apr. 28, 1981	S-16, (2-74923)	4(c)
Oct. 1, 1951	8-K, Nov. 1951	1	Nov. 1, 1981	S-16, (2-74923)	4(d)
Apr. 21, 1952	8-K, Apr. 1952	1	Dec. 1, 1981	10-K, 1981	4(c)
Dec. 1, 1952	S-9, (2-11120)	2(b)(9)	Apr. 29, 1982	10-K, 1982	4(c)
Apr. 15, 1953	8-K, Apr. 1953	2	May 1, 1983	10-K, 1983	4(c)
Apr. 19, 1954	8-K, Apr. 1954	1	Apr. 30, 1984	S-3, (2-95814)	4(c)
Oct. 1, 1954	8-K, Oct. 1954	1	Mar. 1, 1985	10-K, 1985	4(c)
Apr. 18, 1955	8-K, Apr. 1955	1	Nov. 1, 1986	10-K, 1986	4(c)
Apr. 24, 1956	10-K, 1956	1	May 1, 1987	10-K, 1987	4(c)
May 1, 1957	S-9, (2-13260)	2(b)(15)	July 1, 1990	S-3, (33-37431)	4(c)
Apr. 10, 1958	8-K, Apr. 1958	1	Dec. 1, 1990	10-K, 1990	4(c)
May 1, 1959	8-K, May 1959	2	Mar. 1, 1992	10-K, 1992	4(d)
Apr. 18, 1960	8-K, Apr. 1960	1	Apr. 1, 1993	10-Q, June 30, 1993	4(a)
Apr. 19, 1961	8-K, Apr. 1961	1	June 1, 1993	10-Q, June 30, 1993	4(b)
Oct. 1, 1961	8-K, Oct. 1961	2	Nov. 1, 1993	S-3, (33-51167)	4(a)(3)
Mar. 1, 1962	8-K, Mar. 1962	3(a)	Jan. 1, 1994	10-K, 1993	4(a)(3)
June 1, 1964	8-K, June 1964	1	Sept. 2, 1994	8-K, Sept. 1994	4(a)
May 1, 1966	8-K, May 1966	2	May 1, 1996	10Q, June 30, 1996	4(a)
July 1, 1967	8-K, July 1967	2	Nov. 1, 1996	10-K, 1996	4(a)(3)
July 1, 1968	8-K, July 1968	2	Feb. 1, 1997	10-Q, Mar. 31, 1997	4(a)
Apr. 25, 1969	8-K, Apr. 1969	1	April 1, 1998	10-Q, Mar. 31, 1998	4(a)
Apr. 21, 1970	8-K, Apr. 1970	1			

4.85* Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993—Exhibit4(a)).

4.86* Indentures supplemental to Indenture dated as of Oct. 1, 1993:

<u>Dated as of</u>	<u>Previous Filing: Form; Date or File No.</u>	<u>Exhibit No.</u>
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)
Jan. 1, 1994	10-K, 1993	4(b)(3)
Sept. 2, 1994	8-K, Sept. 1994	4(b)
May 1, 1996	10-Q, June 30, 1996	4(b)
Nov. 1, 1996	10-K, 1996	4(b)(3)
Feb. 1, 1997	10-Q, Mar. 31, 1997	4(b)
April 1, 1998	10-Q, Mar. 31, 1998	4(b)

4.87* Indenture date May 1, 1998, between PSCo and The Bank of New York, providing for the issuance of Subordinated Debt Securities (Form 8-K, May 6, 1998—Exhibit 4.2).

4.88* Supplemental Indenture dated May 11, 1998, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998—Exhibit 4.3).

4.89* Preferred Securities Guarantee Agreement dated May 11, 1998, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998—Exhibit 4.4).

4.90* Amended and Restated Declaration of Trust of PSCo Capital and Trust I date May 11, 1998, (Form 8-K, May 6, 1998—Exhibit 4.1).

4.91* Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities (Form 8-K, July 13, 1999, Exhibit 4.1) and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Form 8-K, July 13, 1999, Exhibit 4.2).

SPS

4.92* Indenture, dated as of Aug. 1, 1946, providing for the issuance of First Mortgage Bonds (Registration No. 2-6910, Exhibit 7-A).

4.93* Indentures supplemental to Indenture dated as of Aug. 1, 1946:

<u>Dated as of</u>	<u>Previous Filing: Form; Date or File No.</u>	<u>Exhibit No.</u>
Feb. 1, 1967	2-25983	2-S
Oct. 1, 1970	2-38566	2-T
Feb. 9, 1977	2-58209	2-Y
March 1, 1979	2-64022	b(28)
April 1, 1983 (two)	10-Q, May 1983	4(a)
Feb. 1, 1985	10-K, Aug. 1985	4(c)
July 15, 1992 (two)	10-K, Aug. 1992	4(a)
Dec. 1, 1992 (two)	10-Q, Feb. 1993	4
Feb. 15, 1995	10-Q, May 1995	4
March 1, 1996	333-05199	4(c)

4.94* Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit B).

4.95* Supplemental Indenture dated March 1, 1999, between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit C).

4.96* Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 -Exhibit 4(b)).

- 4.97* Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996—Exhibit 4(a)).
- 4.98* Supplemental Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996—Exhibit 4(b)).
- 4.99* Guarantee Agreement dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996—Exhibit 4(c)).
- 4.100* Amended and Restated Trust Agreement dated Oct. 21, 1996, among SPS, David M. Wilks, as initial depositor, Wilmington Trust Company and the administrative trustees named therein (Form 10-Q, Nov. 30, 1996—Exhibit 4(d)).
- 4.101* Agreement as to Expenses dated Oct. 21, 1996, between SPS and Southwestern Public Service Capital I, (Form 10-K, Dec. 31, 1996—Exhibit F).

NRG Energy, Inc.

- 4.102* Indenture, dated as of June 1, 1997, between NRG and Norwest Bank Minnesota, National Association. (Incorporated herein by reference to Exhibit 4.1 to NRG’s Form S-1 (File no. 333-33397)).
- 4.103* Form of Exchange Notes. (Incorporated herein by reference to Exhibit 4.2 to NRG’s Form S-1 (File no. 333-33397)).
- 4.104* Loan Agreement, dated June 4, 1999 between NRG Northeast Generating LLC, Chase Manhattan Bank and Citibank, N.A. (Incorporated by reference to NRG’s Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 4.105* Indenture between NRG and Norwest Bank Minnesota, National Association, as Trustee dated as of May 25, 1999 (incorporated herein by reference to Exhibit 4.1 to NRG’s current report on Form 8-K (File no. 000-15891) dated May 25, 1999 and filed on May 27, 1999).
- 4.106* Indenture between NRG and NRG Northeast Generating LLC and The Chase Manhattan Bank, as Trustee dated as of February 22, 2000. (Incorporated by reference to NRG’s Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 4.107* NRG Energy Pass-Through Trust 2000-1, \$250,000,000 8.70% Remarketable or Redeemable Securities (“ROARS”) due March 15, 2005. (Incorporated by reference to NRG’s Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 4.108* Trust Agreement between NRG Energy Inc. and The Bank of New York, as Trustee, dated March 20, 2000. (Incorporated by reference to NRG’s Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 4.109* Indenture between NRG Energy Inc. and the Bank of New York, as Trustee dated March 20, 2000, 160,000,000 pounds sterling Reset Senior Notes due March 15, 2020. (Incorporated by reference to NRG’s Form 10-K (file no. 000-15891) for the year ended December 31, 1999)

NSP-Minnesota

- 10.01* Facilities Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (kv) line. (Exhibit 5.06I to File No. 2-54310.)
- 10.02* Transactions Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06J to File No. 2-54310.)
- 10.03* Coordinating Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06K to File No. 2-54310.)

- 10.04* Ownership and Operating Agreement, dated March 11, 1982, between NSP, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034.)
- 10.05* Transmission Agreement, dated April 27, 1982, and Supplement No. 1, dated July 20, 1982, between NSP and Southern Minnesota Municipal Power Agency. (Exhibit 10.02 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034.)
- 10.06* Power Agreement, dated June 14, 1984, between NSP and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034.)
- 10.07* Power Agreement, dated August 1988, between NSP and Minnkota Power Company. (Exhibit 10.08 to Form 10-K for the year 1988, File No. 1-3034.)
- 10.08* Assignment and Assumption Agreement, dated Aug. 18, 2000 between Northern States Power Company and Xcel Energy Inc. (Exhibit 10.08 to Form 10 of NSP-Minnesota, File No. 000-31709)
- 10.09* Copy of Interchange Agreement dated Sept. 17, 1984, and Settlement Agreement dated May 31, 1985, between NSP-Wisconsin, the NSP-Minnesota Company and LSDP. (Filed as Exhibit 10.10 to Form 10-K Report 10-3140 for the year 1985)

PSCo

- 10.10* Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1984—Exhibit 10(c)(1)).
- 10.11* First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1988-Exhibit 10(c)(2)).

SPS

- 10.12* Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (File no. 001-3789), May 14, 1979—Exhibit 3).
- 10.13* Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO, dated July 1, 1978 (Form 8-K, (File no. 001-3789) May 14, 1979—Exhibit 5(A)).
- 10.14* Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO (Form 8-K, (File no. 3789) May 14, 1979—Exhibit 5(B)).
- 10.15* Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982—Exhibit 10(b)).
- 10.16* Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982—Exhibit 10(c)).

Xcel Energy

- 10.17*+ Xcel Energy Omnibus Incentive Plan (Exhibit A to Xcel's Proxy Statement (file no.1-3034) filed Aug. 29, 2000)
- 10.18*+ Xcel Energy Executive Annual Incentive Award (Exhibit B to Xcel's Proxy Statement (file no.1-3034) filed Aug. 29, 2000)

- 10.19+ Xcel Energy Senior Executive Severance
- 10.20*+ Employment Contract of James J. Howard dated March 24, 1999. (Exhibit 10.14 to Form 10-K for the year 1999. File No. 1-3034.)
- 10.21+ Employment Agreement, effective December 15, 1997, between company and Mr. Paul J. Bonavia (Form 10Q, (File no. 001-12927) September 30, 1998—Exhibit 10(a)).
- 10.22*+ The employment agreement, dated March 24, 1999, among Northern States Power Company, New Century Energies, Inc. and Wayne H. Brunetti (Form 10-Q, (File no. 001-12927) March 31, 1999, Exhibit 10(b)).
- 10.23*+ Summary of Terms and Conditions of Employment of James J Howard, Chairman, President and Chief Executive Officer, effective Feb. 1, 1987, as amended and restated effective as of Jan. 28, 1998. (Agreement filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
- 10.24*+ NSP Severance Plan. (Exhibit 10.12 to Form 10-K for the year 1994, File No. 1-3034).
- 10.25*+ NSP Deferred Compensation Plan amended effective Jan. 1, 1993. (Exhibit 10.16 to Form 10-K for the year 1993, File No. 1-3034).
- 10.26*+ Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
- 10.27*+ Stock Equivalent Plan for Non-Employee Directors of Xcel Energy As Amended and Restated Effective Oct. 1, 1997. (Exhibit 10.15 to Form 10-K for the year 1997. File No. 1-3034.)
- 10.28*+ Form of Key Executive Change in Control Agreement (Form 10-K, (file no. 001-12927) December 31, 1998, Exhibit 10(a)(1)).
- 10.29*+ Senior Executive Severance Policy, effective March 24, 1999, between New Century Energies, Inc. and Senior Executives (Form 10-Q, (file no. 001-12927) March 31, 1999, Exhibit 10(a)(2)).
- 10.30*+ Employment Agreement, effective August 1, 1997, between the Company and Mr. Wayne H. Brunetti (Form S-4, Annex I, File No. 33-64951).
- 10.31*+ New Century Energies Omnibus Incentive Plan, effective August 1, 1997 (Form Def 14A, (file no. 001-12927) December 31, 1997—Exhibit A).
- 10.32*+ Directors' Voluntary Deferral Plan (Form 10-K, (file no. 001-12927) December 31, 1998, Exhibit 10(d) (1)).
- 10.33*+ Supplemental Executive Retirement Plan (Form 10-K, (file no. 001-12927) December 31, 1998, Exhibit 10(e) (1)).
- 10.34*+ Salary Deferral and Supplemental Savings Plan for Executive Officers (Form 10-K, (file no. 001-12927) December 31, 1998, Exhibit 10(f) (1)).
- 10.35*+ Salary Deferral and Supplemental Savings Plan for Key Managers (Form 10-K, (file no. 001-12927) December 31, 1998, Exhibit 10(g) (1)).
- 1036*+ Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (Form 10-K, (file no. 001-3280) Dec. 31, 1991—Exhibit 10(e)(2)).
- 10.37*+ Form of Key Executive Severance Agreement, as amended on Aug. 22, and Nov. 27, 1995. (Form 10-K, (file no. 001-3280) Dec. 31, 1995—Exhibit 10(3)(4)).
- 10.38*+ SPS 1989 Stock Incentive Plan as amended April 23, 1996 (Form 10-K, (file no. 001-3789) Aug. 31, 1996—Exhibit 10(b)).

- 10.39* + Director's Deferred Compensation Plan as amended Jan. 10, 1990 (Form 10-K, (file no. 001-3789) Aug. 31, 1996—Exhibit 10(c)).
- 10.40* + Supplemental Retirement Income Plan as amended July 23, 1991 (Form 10-K, (file no. 001-3789) Aug. 31, 1996—Exhibit 10(e)).
- 10.41* + EPS Performance Unit Plan dated Oct. 27, 1992 (Form 10-K, (file no. 001-3789) Aug. 31, 1996—Exhibit 10(a)).

NRG

- 10.42* + Employment Contract, dated as of June 28, 1995, between NRG and David H. Peterson. (Incorporated herein by reference to Exhibit 10.1 to NRG's Form S-1 (File no. 333-33397)).
- 10.43* Indenture, dated as of January 31, 1996, between NRG and Norwest Bank Minnesota, National Association, As Trustee. (Incorporated herein by reference to Exhibit 10.2 to NRG's Form S-1 (File no. 333-33397)).
- 10.44* Revolving Credit Agreement, dated as of March 17, 1997, ("ABN Credit Agreement") among NRG, the banks party thereto and ABN AMRO Bank, N.V. as Agent. (Incorporated herein by reference to Exhibit 10.3 to NRG's Form S-1 (File no. 333-33397)).
- 10.45* Note Agreement, dated August 20, 1993, among NRG Energy Center, Inc. and each of the purchasers named therein. (Incorporated herein by reference to Exhibit 10.4 to NRG's Form S-1 (File no. 333-33397)).
- 10.46* Master Shelf and Revolving Credit Agreement dated August 20, 1993 among NRG Energy Center, Inc., The Prudential insurance Registrants of America and each Prudential Affiliate, which becomes party thereto. (Incorporated herein by reference to Exhibit 10.5 to NRG's Form S-1 (File no. 333-33397)).
- 10.47* Energy Agreement dated February 12, 1988 between NRG (formerly known as Norencor Corporation) and Waldorf Corporation (the "Energy Agreement"). (Incorporated herein by reference to Exhibit 10.6 to NRG's Form S-1 (File no. 333-33397)).
- 10.48* First Amendment to the Energy Agreement dated August 27, 1993.. (Incorporated herein by reference to Exhibit 10.7 to NRG's Form S-1 (File no. 333-33397)).
- 10.49* Second Amendment to the Energy Agreement, dated August 27, 1993.. (Incorporated herein by reference to Exhibit 10.8 to NRG's Form S-1 (File no. 333-33397)).
- 10.50* Third Amendment to the Energy Agreement dated August 27, 1993.. (Incorporated herein by reference to Exhibit 10.9 to NRG's Form S-1 (File no. 333-33397)).
- 10.51* Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among NEO Landfill Gas, Inc, as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.10 to NRG's Form S-1 (File no. 333-33397)).
- 10.52* Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.11 to NRG's Form S-1 (File no. 333-33397)).
- 10.53* Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among Minnesota Methane LLC, as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.12 to NRG's Form S-1 (File no. 333-33397)).

- 10.54* Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.14 to NRG's Form S-1 (File no. 333-33397).
- 10.55* Non Operating Interest Acquisition Agreement dated as of September 12, 1997, by and among NRG and NEO Corporation. (Incorporated herein by reference to Exhibit 10.14 to NRG's Form S-1 (File no. 333-33397).
- 10.56* First Amendment to ABN Credit Agreement, dated as of March 17, 1998. (Incorporated by reference to Exhibit 10.15 of NRG's Form 10-K (File no. 001-15891) for the year ended December 31, 1997).
- 10.57* 364-Day Revolving Credit Agreement dated as of March 17, 1998, among NRG Energy, Inc., the Banks party thereto and ABN AMRO Bank N.V. as Agent. (Incorporated by reference to Exhibit 10.16 of NRG's Form-10K (File no. 001-15891) for the year ended December 31, 1997).
- 10.58*+ Employment Agreements between NRG and certain officers dated as of April 15, 1998. (Incorporated herein by reference to Exhibit 10.17 of NRG's Form 10-Q (File no. 001-15891) for the quarter ended March 31, 1998).
- 10.59* Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated October 13, 1998. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.60* Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated December 23, 1998. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.61* First Amendment to Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated January 15, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.62* Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Arthur Kill generating plants and Astoria gas turbines by and between Consolidated Edison Company of New York, Inc., and NRG Energy, Inc., dated January 27, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.63* Transition Energy Sales Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.64* Transition Power Purchase Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.65* Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.66* Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.67* Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999.(Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)

- 10.68* Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.69* Amendment to the Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated June 11, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.70* Transition Capacity Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.71* Transition Capacity Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.72*+ First Amendment to the Employment Agreement of David H. Peterson, dated June 27, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.73*+ Second Amendment to the Employment Agreement of David H. Peterson, dated August 26, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.74*+ Third Amendment to the Employment Agreement of David H. Peterson, dated October 20, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.75* Swap Master Agreement between Niagara Mohawk Power Corporation and NRG Power Marketing, Inc., dated June 11, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.76* Standard Offer Service Wholesale Sales Agreement between the Connecticut Light And Power Company and NRG Power Marketing, Inc., dated October 29, 1999. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)
- 10.77* 364- day Revolving Credit Agreement among NRG and The Financial Institutions party thereto, and ABN-AMRO Bank, N.V., as Agent, dated as of March 10, 2000. (Incorporated by reference to NRG's Form 10-K (file no. 000-15891) for the year ended December 31, 1999)

Xcel Energy

- 12.01 Statement of Computation of Ratio of Earnings to Fixed Charges
- 16.01* Letter regarding change in accountant (Exhibit 16 to Xcel Energy Form 8-K dated August 21, 2000, File No. 1-3034)
- 23.01 Consent of Independent Accountants.
- 23.02 Consent of Independent Accountants.
- 99.01 Statement pursuant to Private Securities Litigation Reform Act of 1995.
- 99.02* Description of Business of NRG Energy Inc. (Item 1 of NRG Energy, Inc.'s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2000, File No. 333-33397).

(b) *Reports on Form 8-K*—The following report on Form 8-K was filed either during the three months ended Dec. 31, 2000, or between Dec. 31, 2000, and the date of this report.

Oct. 25, 2000 (filed Oct. 25, 2000)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy's third quarter 2000 earnings release.

Oct. 27, 2000 (filed Oct. 27, 2000)—Item 5. Other Events. Re: Disclosure of information related to an Xcel Energy investor relations presentation.

Nov. 28, 2000 (filed Nov. 28, 2000)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy's first and second quarter 2000 income statements.

Dec. 14, 2000 (filed Dec. 18, 2000)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy's \$600 million long-term debt offering.

Jan. 4, 2001 (filed Jan. 4, 2001)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy's Protection Rights Agreement.

Feb. 22, 2001 (filed Feb. 23, 2001)—Item 5. Other Events. Re: Disclosure of the expected increase in purchase power costs for Cheyenne Light, Fuel & Power Co., a subsidiary of Xcel Energy.

Feb. 23, 2001 (filed Feb. 28, 2001)—Item 5. Other Events. Re: Disclosure of the Minnesota Supreme Court's decision to not hear a case related to NSP-Minnesota's conservation incentive recovery for 1998.

Feb. 27, 2001 (filed Feb. 27, 2001)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy reaching a conditional agreement to sell a substantial percentage of its investment in Yorkshire Power.

March 2, 2001 (filed March 2, 2001)—Item 5 and 7. Other Events and Exhibits. Re: Disclosure of Xcel Energy's Dec 31, 2000 year end financial Statements, footnotes and related management's discussion and analysis.

March 15, 2001 (filed March 15, 2001)—Item 5. Other Events. Re: Disclosure of the rate filing to recover expected increase in purchase power costs for Cheyenne Light, Fuel & Power Co., a subsidiary of Xcel Energy.

**XCEL ENERGY INC.
AND SUBSIDIARIES**

**VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
Years Ended December 31, 2000, 1999 and 1998**

	<u>Balance at beginning of period</u>	<u>Additions</u>		<u>Deductions from reserves(1)</u>	<u>Balance at end of year</u>
		<u>Charged to income</u>	<u>Charged to other accounts</u>		
			(in thousands)		
Reserve deducted from related assets:					
Provision for uncollectible accounts:					
2000	<u>\$13,043</u>	<u>\$51,052</u>	<u>\$ 3,953</u>	<u>\$26,698</u>	<u>\$41,350</u>
1999	<u>\$10,018</u>	<u>\$17,841</u>	<u>\$ 5,324</u>	<u>\$20,140</u>	<u>\$13,043</u>
1998	<u>\$15,774</u>	<u>\$16,644</u>	<u>\$ 5,142</u>	<u>\$27,542</u>	<u>\$10,018</u>

(1) Uncollectible accounts written off or transferred to other parties.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

XCEL ENERGY INC.

March 23, 2001

/s/

Edward J. McIntyre

Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

/s/

Wayne H. Brunett

President and Chief Executive Officer
(Principal Executive Officer)

/s/

Edward J. McIntyre

Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/

David E. Ripka

Vice President and Controller
(Principal Accounting Officer)

/s/

James J. Howard

Chairman of the Board

/s/

C. Coney Burgess

Director

/s/

David A. Christensen

Director

/s/

Giannantonio Ferrari

Director

/s/

Roger R. Hemminghaus

Director

/s/

A. Barry Hirschfeld

Director

/s/

Douglas W. Leatherdale

Director

/s/

Albert F. Moreno

Director

/s/

Margaret R. Preska

Director

/s/

A. Patricia Sampson

Director

/s/

Allan L. Schuman

Director

/s/

Rodney E. Slifer

Director

/s/

W. Thomas Stephens

Director