On Aug. 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. (Xcel Energy). Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act (PUHCA). 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 Co. 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. As a stock-for-stock exchange for shareholders of both companies, the merger was accounted for as a pooling-of-interests and accordingly, amounts reported for periods prior to the merger have been restated for comparability with post-merger results.

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 Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); Southwestern Public Service Co. (SPS); Black Mountain Gas Co. (BMG); and Cheyenne Light, Fuel and Power Co. (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 Co. (Viking) 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, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. Xcel Energy's ownership of NRG was 100 percent until the second quarter of 2000, when NRG completed its initial public offering, and then 82 percent until a secondary offering was completed in March 2001. See Note 19 to the Financial Statements for discussion of potential changes in NRG ownership.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Utility Engineering (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International (an international independent power producer).

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 the 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.

Xcel Energy's 2002 Game Plan consists of the following elements:

- Grow the energy supply business;
- Coordinate all energy marketing capabilities;
- Focus retail strategy to support energy supply assets;
- Execute operating and regulatory strategies to unlock and retain the value of regulated businesses;
- Exit non-strategic investments; and
- Deliver what we promise to stakeholders.

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," "project," "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 or have an impact on rates; structures that affect the speed and degree to which competition enters the electric and 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 99.01 to Xcel Energy's Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2001.

RESULTS OF OPERATIONS

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

Contribution to earnings per share	*2001*	*2000*	*1999*
Total regulated earnings before extraordinary items	$1.87	$1.26	$1.51
Total nonregulated/holding company	0.40	0.34	0.19
Extraordinary items (see Note 12)	0.03	(0.06)	–
Total earnings per share (diluted)	$2.30	$1.54	$1.70

For more information on significant factors that had an impact on earnings, see below.

SIGNIFICANT FACTORS THAT IMPACTED 2001 RESULTS

Conservation Incentive Recovery Earnings were increased by 7 cents per share due to the reversal of a Minnesota Public Utilities Commission (MPUC) decision.

In June 1999, the MPUC denied NSP-Minnesota recovery of 1998 incentives associated with state-mandated programs for electric energy conservation. Xcel Energy recorded a $35-million charge in 1999, which reduced earnings by 7 cents per share, 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. During the second quarter of 2001, NSP-Minnesota filed with the MPUC a plan that carried out, among other things, the court's decision.

On June 28, 2001, the MPUC approved the plan and issued an order to that effect shortly thereafter. As a result, the previously recorded liabilities of approximately $41 million (including carrying charges) for potential refunds to customers were no longer required. The plan approved by the MPUC increased revenue by approximately $34 million and increased allowance for funds used during construction by approximately $7 million, increasing earnings by 7 cents per share for the second quarter of 2001.

Based on the new MPUC policy and less uncertainty regarding conservation incentives to be approved, conservation incentives for 2001 are now being recorded on a current basis.

Special Charges – Postemployment Benefits Earnings were decreased by 4 cents per share due to a Colorado Supreme Court decision that resulted in a pretax write-off of $23 million of a regulatory asset related to deferred postemployment benefit costs at PSCo. For more information, see Note 2 to the Financial Statements.

Special Charges – Restaffing Costs During 2001, Xcel Energy expensed pretax special charges of $39 million, or 7 cents per share, for planned staff consolidation costs. The charges related to severance costs for utility operations resulting from restaffing plans of several operating and corporate support areas of Xcel Energy. We accrued for 500 staff terminations that are expected to occur, mainly in the first quarter of 2002, across all regions of Xcel Energy's service territory, but primarily in Minneapolis and Denver. For more information, see Note 2 to the Financial Statements.

Extraordinary Items – Electric Utility Restructuring During early 2001, legislation in both Texas and New Mexico was passed that delayed the planned implementation of restructuring within SPS' service territory for at least five years. Accordingly, in the second quarter of 2001, SPS reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71 – "Accounting for the Effects of Certain Types of Regulation" for its generation business. Based on subsequent financing and regulatory activities clarifying the expected ratemaking impacts of restructuring delays in the fourth quarter of 2001, SPS restored certain regulatory assets totaling $17.6 million as of Dec. 31, 2001, and reported related after-tax extraordinary income of $11.8 million, or 3 cents per share. This represents a reversal of a portion of the 2000 write-offs discussed later. Regulatory assets previously written off were restored only for items currently being recovered in rates and items where future rate recovery is considered probable. For more information, see Note 12 to the Financial Statements.

SIGNIFICANT FACTORS THAT IMPACTED 2000 RESULTS

Special Charges – Merger Costs During 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.

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 expected discontinuation of regulatory accounting for SPS' generation business. Based on expectations at that time for SPS' restructuring, 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, again based on expected restructuring. 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 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 reduction to pretax income in 1999 based on this action, primarily as a reduction of electric utility revenue. As discussed previously under Significant Factors that Impacted 2001 Results, this decision and the related charge were ultimately reversed.

In addition, based on the 1999 change in the MPUC policy on conservation incentives and regulatory uncertainty, in 1999 and 2000 management did not record conservation incentives until they were approved by the MPUC the following year.

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 AND HOLDING COMPANY

Contibution to Xcel Energy's earnings per share	*2001*	*2000*	*1999*
NRG*	$ 0.58	$ 0.46	$ 0.17
Yorkshire Power	0.01	0.13	0.13
Seren Innovations	(0.08)	(0.07)	(0.03)
Planergy International	(0.04)	(0.08)	(0.06)
e prime	0.02	(0.02)	(0.01)
Financing costs and preferred dividends	(0.11)	(0.07)	(0.03)
Other nonregulated	0.02	(0.01)	0.02
Total nonregulated/holding co. earnings per share	$ 0.40	$ 0.34	$ 0.19

** NRG's earnings for 2001 and 2000 in this report exclude earnings of 19 cents per share and 8 cents per share, respectively, related to minority shareholder interests.*

NRG NRG's earnings for 2001 increased primarily due to new acquisitions in Europe and North America, as well as a full year of operation in 2001 of acquisitions made in the fourth quarter of 2000. In addition, NRG's earnings reflected a reduction in the overall effective tax rate and mark-to-market gains related to SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activity." The overall reduction in tax rates was primarily due to higher energy credits, the implementation of state tax planning strategies and a higher percentage of NRG's overall earnings derived from foreign projects in lower tax jurisdictions.

NRG's earnings for 2000 reflected increased electric revenues resulting from 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 also were 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.

Yorkshire Power During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power to Innogy Holdings plc. As a result of this sales agreement, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001. For more information, see Note 11 to the Financial Statements.

Seren Innovations Construction of its broadband communications network in Minnesota and California resulted in losses for 2001, 2000 and 1999. Seren is constructing a combination cable television, telephone and high-speed Internet access system in two locations: St. Cloud, Minn., and Contra Costa County in the East Bay area of northern California. For more information, see Note 15 to the Financial Statements.

Planergy International Competitive markets and delays in government contracts have resulted in continued low margins and losses for Planergy's energy management business in 2001.

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. As a part of the Xcel Energy merger in 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 approximately $17 million (before tax) of goodwill.

e prime e prime's results for the year ended Dec. 31, 2001, reflect the favorable structure of its contractual portfolio, including gas storage and transportation positions, structured products and proprietary trading in natural gas markets.

e prime's results for 2000 were reduced by special charges 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.

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, which include the activity of several nonregulated subsidiaries, 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 after the merger.

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 and Commodity Trading Margins Electric fuel and purchased power expense tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel cost recovery mechanisms for retail customers in several states, most fluctuations in energy costs do not materially affect electric utility margin. However, certain fuel cost recovery mechanisms in various jurisdictions do not allow for complete recovery of all variable production expenses. Therefore, higher costs can result in adverse margin and earnings impacts. Electric utility margins reflect the impact of sharing energy costs and savings relative to a target cost per delivered kilowatt-hour and certain trading margins under the incentive cost adjustment (ICA) ratemaking mechanism in Colorado.

Xcel Energy's commodity trading operations are conducted mainly by PSCo (electric) and e prime (gas). Electric trading activity, initially recorded at PSCo, is partially redistributed to NSP-Minnesota and SPS pursuant to a Joint Operating Agreement approved by the Federal Energy Regulatory Commission (FERC). Trading revenue and costs do not include the revenue and production costs associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Trading revenue and costs associated with NRG's operations are included in nonregulated margins. Margins from these generating assets for utility operations are included in short-term wholesale amounts, discussed later. Trading margins reflect the impact of sharing certain trading margins under the ICA. The following table details electric utility, short-term wholesale and electric and gas trading revenue and margin.

(Millions of dollars)	*Electric Utility*	*Short-Term Wholesale*	*Electric Commodity Trading*	*Gas Commodity Trading*	*Intercompany Eliminations*	*Consolidated Totals*
2001						
Electric utility revenue	$5,607	$788	$ –	$ –	$ –	$ 6,395
Electric and gas trading revenue	–	–	1,337	1,938	(88)	3,187
Electric fuel and purchased power-utility	(2,559)	(613)	–	–	–	(3,172)
Electric and gas trading costs	–	–	(1,268)	(1,918)	88	(3,098)
Gross margin before operating expenses	$3,048	$175	$ 69	$ 20	$ –	$ 3,312
Margin as a percentage of revenue	54.4%	22.2%	5.2%	1.0%	–	34.6%
2000						
Electric utility revenue	$5,107	$567	$ –	$ –	$ –	$ 5,674
Electric and gas trading revenue	–	–	819	1,297	(54)	2,062
Electric fuel and purchased power-utility	(2,106)	(475)	–	–	–	(2,581)
Electric and gas trading costs	–	–	(788)	(1,287)	54	(2,021)
Gross margin before operating expenses	$3,001	$ 92	$ 31	$ 10	$ –	$ 3,134
Margin as a percentage of revenue	58.8%	16.2%	3.8%	0.8%	–	40.5%
1999						
Electric utility revenue	$4,242	$680	$ –	$ –	$ –	$ 4,922
Electric and gas trading revenue	–	–	534	419	(2)	951
Electric fuel and purchased power-utility	(1,329)	(638)	–	–	–	(1,967)
Electric and gas trading costs	–	–	(532)	(417)	2	(947)
Gross margin before operating expenses	$2,913	$ 42	$ 2	$ 2	$ –	$ 2,959
Margin as a percentage of revenue	68.7%	6.2%	0.4%	0.5%	–	50.4%

2001 Comparison to 2000 Electric utility revenue increased by approximately $500 million, or 9.8 percent, in 2001. Electric utility margin increased by approximately $47 million, or 1.6 percent, in 2001. These revenue and margin increases were due to sales growth, weather conditions in 2001 and the recovery of conservation incentives in Minnesota. Increased conservation incentives, including the resolution of the 1998 dispute (as discussed previously) and accrued 2001 incentives increased revenue and margin by $49 million. Temperatures during 2001 increased revenue by approximately $23 million and margin by approximately $13 million. These increases were partially offset by increases in fuel and purchased power costs, which are not completely recoverable from customers in Colorado due to various cost-sharing mechanisms. Revenue and margin also were reduced in 2001 by approximately $30 million due to rate reductions in various jurisdictions agreed to as part of the merger approval process, in comparison to approximately $10 million in 2000.

Short-term wholesale revenue increased by approximately $221 million, or 39.0 percent, in 2001. Short-term wholesale margin increased $83 million, or 90.2 percent, in 2001. These increases are due to the expansion of Xcel Energy's wholesale marketing operations and favorable market conditions for the first six months of 2001, including strong prices in the Western markets, particularly before the establishment of price caps and other market changes.

Electric and gas commodity trading margins, including proprietary (i.e., non-asset based) electric trading and natural gas trading, increased approximately $48 million for the year ended Dec. 31, 2001, compared with the same period in 2000. The increase reflects an expansion of Xcel Energy's trading operations and favorable market conditions, including strong prices in the Western markets, particularly before the establishment of pricing caps and other market changes.

Short-term wholesale margins and electric commodity trading margins for 2002 are not expected to be as strong as margins in 2001 due to declines in energy prices. Margins for the second half of 2001 are more indicative of expected trends in 2002. During 2001, in some Western markets, publicly available power prices ranged from $80 to more than $350 per megawatt-hour on a monthly average. Currently, publicly available forward price information for 2002 for these same areas ranges from $60 to $110 per megawatt-hour on a monthly average.

2000 Comparison to 1999 Electric utility revenue increased by approximately $865 million, or 20.4 percent, in 2000. Electric utility margin increased by approximately $88 million, or 3.0 percent, in 2000. Electric margins reflect the impact of customer sharing due to the ICA mechanism. 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, and to rate reductions agreed to as part of the merger approval process.

Short-term wholesale margin increased due to the expansion of Xcel Energy's wholesale marketing operations and favorable market conditions.

Electric and gas commodity trading revenue increased by a total of approximately $1.2 billion, and the combined trading margin increased by approximately $37 million in 2000. The increase in trading revenue and margin is a result of the expansion of electric and natural gas trading.

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 natural gas margin.

(Millions of dollars)	*2001*	*2000*	*1999*
Gas revenue	$2,053	$1,469	$1,141
Cost of gas purchased and transported	(1,518)	(948)	(683)
Gas margin	$ 535	$ 521	$ 458

2001 Comparison to 2000 Gas revenue increased by approximately $584 million, or 39.8 percent, for 2001, primarily due to increases in the cost of natural gas, which are largely passed on to customers and recovered through various rate adjustment clauses in most of the jurisdictions in which Xcel Energy operates. Gas margin increased by approximately $14 million, or 2.7 percent, for 2001 due to sales growth and a rate increase in Colorado. These gas revenue and margin increases were partially offset by the impact of warmer temperatures in 2001, which decreased gas revenue by approximately $38 million and gas margin by approximately $16 million.

2000 Comparison to 1999 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. Temperatures during 2000 compared with 1999 increased gas revenue by $82 million and gas margins by $33 million. Customer growth also contributed to margin increases in 2000.

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

(Millions of dollars)	*2001*	*2000*	*1999*
Nonregulated and other revenue	$3,177	$2,204	$ 711
Earnings from equity investments	217	183	112
Nonregulated cost of goods sold	(1,657)	(1,007)	(310)
Nonregulated margin	$1,737	$1,380	$ 513

2001 Comparison to 2000 Nonregulated revenue and margin increased for 2001, largely due to NRG's acquisition of generating facilities, increased demand for electricity, market dynamics, strong performance from existing assets and higher market prices for electricity. Earnings from equity investments for 2001 increased compared with 2000, primarily due to increased equity earnings from NRG projects, which offset lower equity earnings from Yorkshire Power. As a result of a sales agreement to sell the majority of its investment in Yorkshire Power, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001.

2000 Comparison to 1999 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. Nonregulated margin increased by approximately $867 million in 2000, largely due to NRG's acquisition of generation facilities during 2000.

Non-Fuel Operating Expense and Other Items Other utility operating and maintenance expense for 2001 increased by approximately $60 million, or 4.1 percent, compared with 2000. The change is largely due to increased plant outages, higher nuclear operating costs, bad debt reserves reflecting higher energy prices, increased costs due to customer growth and higher performance-based incentive costs.

Other utility operating and maintenance expense for 2000 increased by approximately $69 million, or 5.0 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, higher nuclear operating costs and higher employee-related costs.

Depreciation and amortization expense increased $157 million, or 19.8 percent, in 2001 and $113 million, or 16.6 percent, in 2000, primarily due to acquisitions of generating facilities by NRG and increased additions to utility plant.

Interest expense increased $125 million, or 19 percent, in 2001 and $243 million, or 58.7 percent, in 2000, primarily due to increased debt levels to finance several asset acquisitions by NRG.

Interest income and other – net increased by approximately $54 million for the year ended Dec. 31, 2001, compared with the same period in 2000. This increase was primarily the result of a credit swap at NRG, NRG mark-to-market gains on foreign debt, NRG interest income due to increased affiliate receivables related to loans to West Coast Power and gains from the sale of PSCo assets.

As discussed in Note 8 to the Financial Statements, Xcel Energy's effective tax rate before extraordinary items was 28.0 percent for the year ended Dec. 31, 2001, and 35.8 percent for the same period in 2000. The change in the effective tax rate reflects changes in the 2001 effective tax rate at NRG and the non-deductibility of certain merger costs in 2000. As discussed previously, NRG's annual effective tax rate for 2001 declined due to higher energy tax credits, the implementation of state tax planning strategies and a higher percentage of NRG's overall earnings derived from foreign projects in lower tax jurisdictions.

Weather Xcel Energy's earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase expenses, which may not be fully recoverable. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses, which affects overall results. 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 2001 had minimal impact on earnings per share.
- Weather in 2000 increased earnings by an estimated 1 cent per share.
- Weather in 1999 decreased earnings by an estimated 9 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:

General Economic Conditions The slower United States economy, and the global economy to a lesser extent, may have a significant impact on Xcel Energy's operating results. Current economic conditions have resulted in a decline in the forward price curve for energy and may decrease the need for additional power supply. Xcel Energy expects the economic conditions to have a significant impact on commodity trading margins, which are not expected to be as strong as those experienced in 2001. In addition, certain operating costs, such as insurance and security, have increased due to the economy and the terrorist attacks of Sept. 11, 2001. We do not believe these events will affect our access to insurance markets. However, Xcel Energy could experience other significant impacts from a weakened economy.

Utility Industry Changes and Restructuring The structure of the electric and natural gas utility industry continues to change. Merger and acquisition activity over the past few years has been significant as utilities combine to capture economies of scale or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide nondiscriminatory access to the use of their transmission systems.

In December 2001, the FERC approved Midwest Independent Transmission System Operator, Inc. (MISO) as the Midwest independent system operator responsible for operating the wholesale electric transmission system. Accordingly, in compliance with the FERC's Order No. 2000, Xcel Energy turned over operational control of its transmission system to MISO in January 2002.

Some states have begun to allow retail customers to choose their electricity supplier, and many other states are considering retail access proposals. However, the experience of the state of California in instituting competition, as well as the bankruptcy filing of Enron, have caused delays in industry restructuring.

Major issues that must be addressed include mitigating market power, divestiture of generation capacity, transmission constraints, legal separation, 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 restructuring proceedings in the electric utility jurisdictions it serves 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 the delay of restructuring for SPS in Texas and New Mexico, see Note 12 to the Financial Statements.

In addition, industry restructuring may impact the wholesale power markets, in which NRG operates. The independent system operators who oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. For example, the independent system operator for the New York Power Pool and the California independent system operator have recently imposed price limitations. These types of price limitations and other mechanisms in New York, California, the New England Power Pool and elsewhere may adversely impact the profitability of NRG's generation facilities that sell energy into the wholesale power markets. Finally, the regulatory and legislative changes that have recently been enacted in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by independent system operators.

Enron Impacts Industry changes also may be implemented as a result of the bankruptcy filing of Enron, a large energy company. Such changes may be invoked by various regulatory agencies, including but not limited to the SEC, the FERC or state regulatory agencies. Management is unable to predict the impact of such changes, if any, on any component of the energy industry. See additional discussion in Note 15 to the Financial Statements.

California Power Market NRG operates in and sells to the wholesale power market in California. During 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 or otherwise pay obligations, or would consider discontinuing energy service to customers to avoid incurring costs that are not recoverable. However, the extent and timing of such financial support that will be made available to California utilities is unknown at this time.

See Note 15 to the Financial Statements for a description of 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.

Critical Accounting Policies Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles (GAAP) requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most significant to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policy	*Judgments/Uncertainties Affecting Application*	*See Additional Discussion At*
Regulatory Mechanisms & Cost Recovery	– External regulator decisions, requirements and regulatory environment – Anticipated future regulatory decisions and their impact – Impact of deregulation and competition on ratemaking process and ability to recover costs	Management's Discussion and Analysis: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to Consolidated Financial Statements Note 1, Note 12, Note 15
Nuclear Plant Decommissioning	– Costs of future decommissioning – Availability of facilities for waste disposal – Approved methods for waste disposal – Useful lives of nuclear power plants	Notes to Consolidated Financial Statements Note 1, Note 15, Note 16
Environmental Issues	– Approved methods for cleanup – Responsible party determination – Governmental regulations and standards – Results of ongoing research and development regarding environmental impacts	Management's Discussion and Analysis: Factors Affecting Results of Operations Environmental Matters Notes to Consolidated Financial Statements Note 1, Note 15
Unbilled Revenue	– Projecting customer energy usage – Estimating impacts of weather and other usage-affecting factors for unbilled period	Notes to Consolidated Financial Statements Note 1
Benefit Plan Accounting	– Future rate of return on pension and other plan assets – Interest rates used in valuing benefit obligation	Notes to Consolidated Financial Statements Note 1, Note 10
Derivative Financial Instruments	– Market conditions in the energy industry, especially the effects of price volatility on contractual commitments – Market conditions in foreign countries – Regulatory and political environments and requirements	Management's Discussion and Analysis: Derivatives, Risk Management and Market Risk Notes to Consolidated Financial Statements Note 1, Note 13, Note 14
Income Tax Reserves	– Application of tax statutes and regulations to transactions – Anticipated future decisions of tax authorities – Ability of tax authority decisions/positions to withstand legal challenges and appeals	Management's Discussion and Analysis: Factors Affecting Results of Operations Tax Matters Notes to Consolidated Financial Statements Note 1, Note 8, Note 15
Uncollectible Receivables	– Economic conditions affecting customers, suppliers and market prices – Regulatory environment and impact of cost recovery constraints on customer financial condition – Outcome of litigation and bankruptcy proceedings	Management's Discussion and Analysis: Factors Affecting Results of Operations California Power Market Notes to Consolidated Financial Statements Note 1, Note 15
Asset Valuation	– Regional economic conditions surrounding asset operation and affecting market prices – Foreign currency valuation changes – Regulatory and political environments and requirements – Levels of future penetration and customer growth	Management's Discussion and Analysis: Factors Affecting Results of Operations Impact of Nonregulated Investments Notes to Consolidated Financial Statements Note 1, Note 15

Regulation Xcel Energy is a registered holding company under the PUHCA. As a result, Xcel Energy, its utility subsidiaries and certain of its nonutility subsidiaries are subject to extensive regulation by the SEC under the 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, the 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 2002 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.

Most of the retail rate schedules for Xcel Energy's utility subsidiaries provide for periodic adjustments to billings and revenues to allow for recovery of 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 and Colorado, changes in electric capacity costs are not recovered through these rate adjustment mechanisms. For Wisconsin electric operations, where automatic cost-of-energy adjustment clauses are not allowed, 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 mechanism that 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 regulatory assets certain costs that are expected to be recovered from customers in future periods and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, nonregulated enterprises would expense these costs and recognize the income in the current period. 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 effect on Xcel Energy's results of operations in the period the write-off is recorded.

At Dec. 31, 2001, Xcel Energy reported on its balance sheet regulatory assets of approximately $502 million and regulatory liabilities of approximately $484 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 17 to the Financial Statements for further discussion of regulatory deferrals.

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 an annual rate of $11 million for the period of August 2000 through July 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 ratemaking purposes through 2002;
- continue the electric 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, to reflect no earnings sharing in 2003 since new base rates would have recently been established, and to increase potential bill credits if quality standards are not met; and
- develop a QSP for the natural gas operations to be effective for calendar years 2002 through 2007.

As part of the merger approval process in Minnesota, NSP-Minnesota agreed to:
- reduce its Minnesota electric rates by $10 million annually through 2005;
- not increase its electric rates through 2005, except under limited circumstances;
- not seek 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; 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 through December 2004;
- share net nonfuel 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 merger.

PSCo Performance-Based Regulatory Plan The Colorado Public Utilities 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 between customers and shareholders of earnings in excess of the following limits:
    - 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 through 2006
- an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2006;
- a gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to gas leak repair time and customer service through 2007; and
- an ICA that provides for the sharing of energy costs and savings relative to an annual baseline cost per delivered kilowatt-hour. According to the terms of the merger rate agreement in Colorado, the annual baseline cost will be reset in 2002, based on a 2001 test year.

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 estimated no customer refund obligation for 2001 under the earnings test. In November 2000, the CPUC ruled on the unresolved issues related to the 1998 earnings test that will result in the reduction of customer rates by $5.1 million effective January 2001.

During 2001, PSCo settled all unresolved issues related to the 1999 and 2000 QSP electric reliability performance measure. An accrual for related customer refunds of $8.2 million was recorded and paid in 2001. PSCo has recorded an estimated customer refund obligation for the 2001 QSP electric reliability performance measure of approximately $4.2 million.

SPS Earnings Test In Texas, until June 2001, SPS operated under an earnings test in which excess earnings were 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 filed with the PUCT a Notice of Disagreement, 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 in the 1999 report and found that SPS had excess earnings of $11.7 million. This decision was appealed by SPS to the District Court. On Dec. 11, 2001, SPS entered into an overall settlement of all earnings issues for 1999 through 2001, which reduced the excess earnings for 1999 to $7.3 million and found that there were no excess earnings for 2000 or through June 2001. The settlement also provided that the remaining excess earnings for 1999 could be used to offset approved transition costs that SPS is seeking to recover in a pending case at the PUCT. The PUCT approved the overall settlement on Jan. 10, 2002.

Tax Matters As further discussed in Note 15 to the Financial Statements, a subsidiary of PSCo is working with the Internal Revenue Service (IRS) to resolve an income-tax dispute regarding deductions for loan interest expense related to company owned life insurance (COLI). Late in 2001, Xcel Energy received a technical advice memorandum from the IRS, which communicated a position adverse to PSCo. After consultation with tax counsel, it is Xcel Energy's position that the IRS determination is not supported by tax law. Although the ultimate outcome is uncertain at this time, management believes the resolution of this matter will not have a material adverse impact on Xcel Energy's financial position, results of operations or cash flows. In addition, pending resolution of this matter, annual earnings will continue to include tax benefits associated with the COLI policy loan interest deductions. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2001, would reduce earnings by an estimated $197 million (after tax), or 57 cents per share. In 2002, these tax benefits are expected to contribute approximately $31 million, or 9 cents per share, to Xcel Energy earnings.

Environmental Matters Our environmental costs include payments for 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 to the environment. A trend of greater environmental awareness and increasingly stringent regulation has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance. 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 our operating expenses for environmental monitoring and disposal of hazardous materials and wastes were approximately:

- $146 million in 2001
- $144 million in 2000
- $128 million in 1999

We expect to expense approximately $161 million per year for 2002–2006 for similar costs. 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 our facilities, which include the costs of constructing spent nuclear fuel storage casks, were approximately:

- $136 million in 2001
- $57 million in 2000
- $126 million in 1999

We expect to incur approximately $41 million in capital expenditures for compliance with environmental regulations in 2002 and approximately $156 million for 2002–2006. See Notes 15 and 16 to the Financial Statements for further discussion of our environmental contingencies.

Impact of Nonregulated Investments Xcel Energy's earnings from nonregulated operations have increased significantly due to acquisitions, primarily at NRG. Xcel Energy expects to continue investing in nonregulated projects, including domestic and international power production projects through NRG, natural gas marketing and trading through e prime and construction projects through Utility Engineering. 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.

Xcel Energy's earnings from nonregulated subsidiaries, other than NRG, also include investments in international projects (primarily in Argentina) through Xcel Energy International, and broadband communications systems through Seren. Management currently intends to hold and operate these investments, but is evaluating their strategic fit in Xcel Energy's business portfolio. As of Dec. 31, 2001, Xcel Energy's investment in Seren was approximately $232 million. Seren had capitalized $190 million for plant in service and had incurred another $60 million for construction work in progress for these systems at Dec. 31, 2001. Xcel Energy International's investment in Argentina is $102 million. Given the political and economic climate in Argentina, Xcel Energy continues to closely monitor the investment for asset impairment. Currently, management believes that no impairment exists.

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 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.

Inflation Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. Since late 2001, the Argentine peso has been significantly devalued due to the inflationary Argentine economy. Xcel Energy will continue to experience related currency translation adjustments through Xcel Energy International. See further discussion at Note 15 to the Financial Statements.

PENDING ACCOUNTING CHANGES

SFAS No. 142 In June 2001, the Financial Accounting Standards Board (FASB) approved the issuance of SFAS No. 142 – "Goodwill and Other Intangible Assets." This statement requires new accounting for intangible assets, including goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill will no longer be amortized to comply with the provisions of SFAS No. 142. Instead, goodwill and intangible assets that will not be amortized are to be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value. An impairment test is required to be performed within six months of the date of adoption, and the first annual impairment test must be performed in the year the statement is initially adopted.

As required, Xcel Energy and its subsidiaries adopted SFAS No. 142 on Jan. 1, 2002. At Dec. 31, 2001, Xcel Energy had unamortized intangible assets of $166 million, including $69 million of goodwill, mainly at its nonregulated subsidiaries. These amounts and all intangible assets and goodwill acquired in the future will be accounted for under the new accounting standard. The new accounting standard is expected to initially increase earnings by an immaterial amount due to the elimination of regular amortization expense, but in the future could cause periodic reductions in earnings when impairment write-downs of goodwill and/or intangible assets are required. Expense recognized for amortization of goodwill in 2001 was $4 million. Xcel Energy does not expect to recognize any asset impairments as a result of adopting SFAS No. 142 in the first quarter of 2002.

SFAS No. 143 In June 2001, the FASB approved the issuance of SFAS No. 143 – "Accounting for Asset Retirement Obligations." This statement will require Xcel Energy to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset's life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires that a gain or loss be recognized at that time.

Xcel Energy currently follows industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in accumulated depreciation. At Dec. 31, 2001, Xcel Energy recorded and recovered in rates $623 million of decommissioning obligations and had estimated discounted decommissioning cost obligations of $878 million.

If Xcel Energy adopted the standard on Jan. 1, 2002, the initial value of the liability, including cumulative interest expense through that date, would have been approximately $757 million, with a corresponding increase to net plant assets of approximately $625 million. The resulting cumulative effect adjustment for unrecognized depreciation and other expenses under the new standard is approximately $132 million. Management expects that the entire transition amount would be recoverable in rates and, therefore, would recognize an additional regulatory asset upon adoption of SFAS No. 143 rather than incur a cumulative effect charge against earnings.

SFAS No. 143 also will affect Xcel Energy's accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Xcel Energy expects that these costs, which have yet to be estimated, will be reclassified from accumulated depreciation to regulatory liabilities based on the treatment of these costs in rates. Xcel Energy plans to adopt SFAS No. 143 as required on Jan. 1, 2003.

SFAS No. 144 In October 2001, the FASB issued SFAS No. 144 – "Accounting for the Impairment or Disposal of Long-Lived Assets," which supercedes previous guidance for measurement of asset impairments. SFAS No. 144 was adopted by Xcel Energy as required on Jan. 1, 2002, and will be applied on a prospective basis. Xcel Energy does not expect to recognize any asset impairments as a result of adopting SFAS No. 144 in the first quarter of 2002.

DERIVATIVES, RISK MANAGEMENT AND MARKET RISK

Business and Operational Risk Xcel Energy and its subsidiaries are exposed to commodity price risks in their generation, retail distribution and energy trading operations. In certain jurisdictions, purchased power expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, we are exposed to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, we recover our purchased power expenses and natural gas costs based on fixed price limits or under negotiated sharing mechanisms.

Commodity price risk is managed by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil and derivative financial instruments. Xcel Energy's risk management policy allows us to manage the market price risk within our rate-regulated operations to the extent such exposure exists. Management is limited under the policy to enter into only transactions that reduce market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. This jurisdiction allows us to recover the gains and losses on derivative instruments used to reduce our exposure to market price risk.

Xcel Energy and its subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. Xcel Energy manages this market price risk by entering into firm power sales agreements for approximately 60 to 75 percent of its electric capacity and energy from each generation facility, using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed priced electric energy requirements. Xcel Energy's risk management policy allows us to manage the market price risks and provides guidelines for the level of price risk exposure that is acceptable within our operations.

Xcel Energy is exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from our equity method investments that own electric operations. Xcel Energy manages this market price risk through our involvement with the management committee or board of directors of each of these ventures. Our risk management policy does not cover the activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk Xcel Energy and its subsidiaries are exposed to fluctuations in interest rates where we are required to enter into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations is mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in the Company having primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy's risk management policy allows management to reduce its interest rate exposure from variable rate debt obligations.

At Dec. 31, 2001 and 2000, a 100 basis point change in the benchmark rate on Xcel Energy's variable debt would impact net income by approximately $29.9 million and $15.8 million, respectively. See Note 13 to the Financial Statements for a discussion of Xcel Energy and subsidiaries' interest rate swaps.

Currency Exchange Risk Xcel Energy and its subsidiaries have certain investments in foreign countries exposing us to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project as well as the risk relative to the earnings and cash flows generated from such operations. Xcel Energy manages its exposure to changes in foreign currency by entering into derivative instruments as determined by management. Our risk management policy provides for this risk management activity.

As discussed in Note 18 to the Financial Statements, Xcel Energy has substantial investments in foreign projects (through NRG and other subsidiaries), which expose us to currency translation risk. Cumulative translation adjustments (included in the Consolidated Statement of Stockholders' Equity as Accumulated Other Comprehensive Income) experienced to date have been material and may continue to occur at levels significant to our financial position. As of Dec. 31, 2001, NRG had two foreign currency exchange contracts with notional amounts of $46.3 million. If the contracts had been discontinued on Dec. 31, 2001, NRG would have owed the counterparties approximately $2.4 million.

Trading Risk Xcel Energy and its subsidiaries conduct various trading operations and power marketing activities including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Xcel Energy's risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by our risk management committee made up of management personnel not involved in the trading operations.

Our trading operations and power marketing activities measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into but not closed using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential loss in fair value on the outstanding transactions, contracts and obligations 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. The VaR model employs a 95-percent confidence interval level based on historical price movement, lognormal price distribution assumption and various holding periods of five days and three days for electricity and two days for natural gas.

As of Dec. 31, 2001, the calculated VaRs were:

(Millions of dollars)	*Year Ended Dec. 31, 2001*	*Average*	*During 2001 High*	*Low*
Operations				
Short-term wholesale – North *(a)*	1.00	0.81	1.68	0.09
Short-term wholesale – South *(b)*	8.11	9.34	13.48	3.10
Electric commodity trading	0.52	1.71	7.37	0.16
Gas commodity trading	0.16	0.15	0.52	0.01
Gas retail marketing	0.69	0.39	0.94	0.13
NRG power marketing	71.70	78.80	126.60	58.60

(a) Short-term wholesale – North primarily represents NSP-Minnesota.

(b) Short-term wholesale – South primarily represents PSCo. Measurement of short-term wholesale – South VaR began in October 2001.

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

(Millions of dollars)	*Year Ended Dec. 31, 2000*	*Average*	*During 2000 High*	*Low*
Operations				
Short-term wholesale – North *(c)*	0.68	0.36	2.29	0.01
Electric commodity trading *(c)*	2.25	0.69	3.53	0.04
Gas commodity trading *(c)*	0.01	0.11	0.42	0.01
Gas retail marketing *(c)*	0.21	0.22	0.60	0.04
NRG power marketing	116.00	80.00	125.00	50.00

(c) Amounts have been restated for consistency with Dec. 31, 2001, assuming similar holding periods in the VaR calculations.

Previously, Xcel Energy calculated VaR using a 21-day holding period, as shown below. As markets mature and gain liquidity, shorter holding periods more accurately reflect the risk. In 2001, Xcel Energy changed its holding period for natural gas from 21 days to two days because the gas trading market is mature and traders can liquidate positions in one or two days. The electricity market is still relatively immature and less liquid than the gas market, so Xcel Energy uses a five-day holding period in its electricity VaR calculation. Xcel Energy's revised holding periods are generally consistent with current industry standard practice.

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

(Millions of dollars)	*Year Ended Dec. 31, 2000*	*Average*	*During 2000 High*	*Low*
Operations				
Short-term wholesale – North	1.40	0.73	4.70	0.01
Electric commodity trading	4.62	1.42	7.23	0.08
Gas commodity trading	0.03	0.35	1.37	0.02
Gas retail marketing	0.69	0.70	1.94	0.12

Credit Risk In addition to the risks discussed previously, Xcel Energy and its subsidiaries are exposed to credit risk in our 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 our 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 15 to the Financial Statements for a discussion of NRG's receivables related to the California power market and a discussion of our exposure to Enron's bankruptcy.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

(Millions of dollars)	*2001*	*2000*	*1999*
Net cash provided by operating activities	$ 1,584	$ 1,408	$ 1,325

Cash provided by operating activities increased during 2001, compared with 2000, primarily due to higher net income, depreciation and improved working capital. Cash provided by operating activities increased during 2000, compared with 1999, primarily due to improved working capital.

(Millions of dollars)	*2001*	*2000*	*1999*
Net cash used in investing activities	$(5,168)	$(3,347)	$(2,953)

Cash used in investing activities increased during 2001, compared with 2000, primarily due to increased levels of nonregulated capital expenditures and asset acquisitions, primarily at NRG. The increase was partially offset by Xcel Energy's sale of the majority of its investment in Yorkshire Power. Cash used in investing activities increased during 2000, compared with 1999, primarily due to acquisitions of existing generating facilities by NRG.

(Millions of dollars)	*2001*	*2000*	*1999*
Net cash provided by financing activities	$ 3,713	$ 2,016	$ 1,668

Cash provided by financing activities increased during 2001, compared with 2000, primarily due to increased short-term borrowings and net long-term debt issuances, mainly to fund NRG acquisitions. 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.

See discussion of trends, commitments and uncertainties with the potential for future impact on cash flow and liquidity under Capital Sources.

CAPITAL REQUIREMENTS

Capital Expenditures and Nonregulated Investments The estimated cost as of Dec. 31, 2001, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements for the years 2002, 2003 and 2004 are shown in the table below.

(Million of dollars)	*2002*	*2003*	*2004*
Electric utility	$ 851	$ 878	$ 908
Gas utility	141	107	111
Common utility	128	114	118
Total utility	1,120	1,099	1,137
NRG	1,600	1,500	1,500
Other nonregulated	73	36	37
Total capital expenditures	2,793	2,635	2,674
Sinking funds and debt maturities	682	719	335
Total capital requirements	$3,475	$3,354	$3,009

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 15 to the Financial Statements.

Xcel Energy's subsidiaries expect to invest significant amounts in nonregulated projects in the future. Financing requirements for non-regulated project investments, including NRG, 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. Xcel Energy's investment in exempt wholesale generators and foreign utility companies, which includes NRG and other Xcel Energy subsidiaries, is currently limited to 50 percent of consolidated retained earnings, as a result of the PUHCA restrictions. At Dec. 31, 2001, such investments were 37.7 percent of consolidated retained earnings. Xcel Energy has requested an increase in the limit to 100 percent in the first quarter of 2002.

NRG expects to invest approximately $1.6 billion in 2002 for nonregulated projects and property, which include acquisitions and project investments. NRG's future capital requirements may vary significantly. For 2002, NRG's capital requirements reflect expected acquisitions of existing generation facilities, including FirstEnergy Corp. generating assets and the Conectiv fossil assets. This level of NRG spending for 2002 (and the levels shown in the table above for 2002 through 2004) reflect a lower forecast after announcement of Xcel Energy's tender offer for NRG shares on Feb. 15, 2002. See further discussion in Note 19 to the Financial Statements.

Contractual Obligations and Other Commitments Xcel Energy has a variety of contractual obligations and other commercial commitments that represent prospective requirements in addition to its capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in the Consolidated Statements of Capitalization and Notes 3, 4, 13 and 15 to the Financial Statements.

(Thousands of dollars)			*Payments Due by Period*		
Contractual obligations	*Total*	*Less than 1 year*	*1–3 years*	*4–5 years*	*After 5 years*
Long-term debt	$12,195,472	$ 657,518	$1,009,005	$2,927,454	$ 7,601,495
Capital lease obligations	1,438,000	77,000	148,000	140,000	1,073,000
Operating leases	330,331	53,887	99,797	92,557	84,090
Unconditional purchase obligations	12,430,361	3,124,290	2,244,543	5,495,528	1,566,000
Other long-term obligations	918,900	50,676	93,743	88,235	686,246
Short-term debt	2,224,812	2,224,812	–	–	–
Other short-term liabilities	11,500	11,500	–	–	–
Total contractual cash obligations	$29,549,376	$6,199,683	$3,595,088	$8,743,774	$11,010,831

(Thousands of dollars)	*Total Amounts*	*Amount of Commitment Expiration Per Period*			
Other commercial commitments	*Committed*	*Less than 1 year*	*1–3 years*	*4–5 years*	*Over 5 years*
Lines of credit	$ –	$ –	$ –	$ –	$ –
Standby letters of credit	222,287	215,318	6,969	–	–
Guarantees	1,871,930	275,663	737,195	63,686	795,386
Standby repurchase obligations	–	–	–	–	–
Other commercial commitments	–	–	–	–	–
Total commercial commitments	$2,094,217	$490,981	$744,164	$63,686	$795,386

Common Stock Dividends Xcel Energy adopted a dividend of $1.50 per share on an annual basis for 2001. 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. As a result of its registration as a holding company under the PUHCA, Xcel Energy is required to maintain a common equity ratio of 30 percent or higher in its consolidated capital structure. For this purpose, common equity (including minority interest) at Dec. 31, 2001 was 30.4 percent of total capitalization. Consolidated project-related, nonrecourse debt at the subsidiary level is included in calculating the overall capital structure of Xcel Energy. As a result, Xcel Energy may experience constraints on available capital sources that may be affected by factors including earnings levels, project acquisitions and the financing actions of our subsidiaries.

Over the long term, Xcel Energy's equity investments in and acquisitions of nonregulated projects may be financed at the nonregulated subsidiary level from internally generated funds or the issuance of subsidiary debt. 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.

Short-Term Funding Sources Xcel Energy uses a number of sources to fulfill short-term funding needs. Primary among these is operating cash flow, but also included are short-term borrowing arrangements such as notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for utility construction expenditures and non-regulated project investments, as discussed previously in Capital Requirements. Another significant short-term funding need is the dividend payment requirement, as discussed previously in Common Stock Dividends.

Operating cash flow as a source of short-term funding is reasonably likely to be affected by such operating factors as weather; regulatory requirements, including rate recovery of costs, environmental regulation compliance and industry deregulation; changes in the trends for energy prices and supply; as well as operational uncertainties that are difficult to predict. See further discussion of such factors under Income Statement Analysis and Factors Affecting Results of Operations.

Short-term borrowing as a source of short-term funding is affected by access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. If current debt levels are perceived to be at or higher than standard industry levels or those levels that can be sustained by current operating levels, access to reasonable short-term borrowings could be limited. These factors are evaluated by credit rating agencies that review Xcel Energy and its subsidiary operations on an ongoing basis. The levels of risk from limited access to cost-effective capital is significantly higher at NRG, which could result in higher short-term funding needs at Xcel Energy if NRG funding requires an investment by Xcel Energy. For additional information on Xcel Energy's short-term borrowing arrangements, see Note 3 to the Financial Statements.

Xcel Energy's access to capital markets is dependent in part on credit agency reviews. In February 2002, Moody's Investor Services placed Xcel Energy's long-term debt and preferred securities ratings under review for possible downgrade, reflecting possible pressure on Xcel Energy's credit profile resulting from NRG restructuring. In December 2001, Moody's placed NRG's corporate securities under review for possible downgrade following NRG's announcement of its planned acquisition of generation assets from FirstEnergy Corp. According to Moody's, the review will address NRG's ability to finance the acquisition and the effect of the acquisition on NRG's liquidity and coverage ratios. In December 2001, Fitch Ratings placed Xcel Energy on ratings "watch negative." According to Fitch, the ratings watch for Xcel Energy reflects the potential heavy capital needs of NRG and the possibility that Xcel Energy may have to provide funding or credit support on behalf of NRG. The securities of NSP-Minnesota, NSP-Wisconsin and SPS also were placed on ratings "watch negative" in consideration of Fitch's policy regarding the linkage between ratings of subsidiaries and the parent. In February 2002, Fitch reaffirmed the status of Xcel Energy's rating. These ratings reflect the views of Moody's and Fitch. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating company.

NRG Public Offerings During the second quarter of 2000, NRG completed an initial public offering (IPO) of approximately 32.4 million shares priced at $15 per share. Upon completion of the IPO, Xcel Energy owned approximately 147.6 million shares of NRG class A common stock, or 82 percent of NRG's outstanding shares. 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 to NRG was accounted for as a gain related to the reduction of Xcel Energy's ownership in NRG. This gain of $216 million was not recorded in earnings, but consistent with Xcel Energy's accounting policy, was recorded as an increase in the common stock premium component of stockholders' equity.

In March 2001, NRG completed a secondary public offering of 18.4 million shares of common stock at a price of $27 per share and issued 11.5 million corporate units at a price of $25 per unit. The net proceeds from the offering were approximately $753 million, including $478 million recorded in NRG's common equity and $275 million recorded in long-term debt instruments of NRG. The offering's net proceeds were used exclusively by NRG for general corporate purposes, including funding a portion of NRG's project investments and other capital requirements. No proceeds of these offerings were received by Xcel Energy. This secondary offering caused Xcel Energy's ownership interest in NRG to decline from approximately 82 percent to approximately 74 percent. A portion of the proceeds to NRG ($242 million) was accounted for as a gain related to the reduction of Xcel Energy's ownership in NRG, and was recorded as an increase in the common stock premium component of stockholders' equity. Management has concluded that these offerings of NRG stock do not affect Xcel Energy's ability to use the pooling-of-interests method of accounting for the merger of NSP and NCE.

As a result of the merger to form Xcel Energy, constraints related to the accounting treatment as a pooling-of-interests transaction limit various actions, including significant divestitures that can be taken or even contemplated until August 2002. As a part of an evaluation of potential strategies and to more fully respond to investor questions, during 2001 management began investigating restructuring options and constraints. In mid-2001, it was determined that an additional restriction to future divestitures exists. Under current tax rules, a June 1998 call of PSCo nonvoting preferred stock that occurred shortly after the merger of PSCo and SPS to form NCE triggered a five-year waiting period beginning in June 1998 for any tax-free spin-offs. After consoltation with legal counsel and tax advisors, Xcel Energy concluded that this restriction would prevent a tax-free spin of subsidiary stock, including NRG, until June 2003.

In December 2001, the Xcel Energy board recommended that Xcel Energy management continue to monitor all aspects of the future funding and structure of NRG, including among other things, the amount and timing of expected capital expenditures by NRG; the issuance by NRG of additional debt or public equity and the infusion by Xcel Energy of additional equity into NRG; and examine the possible reacquisition by Xcel Energy of the outstanding public NRG stock. In February 2002, Xcel Energy announced that its board of directors approved plans to commence an exchange offer by which Xcel Energy would acquire all of the outstanding publicly held shares of NRG in exchange for shares of Xcel Energy common stock. See further discussion in Note 19 to the Financial Statements.

NRG Financing Capabilities As part of the independent power producer sector, NRG has recently been experiencing tightening credit standards. As discussed in Note 19 to the Financial Statements, in response to this situation, Xcel Energy is planning to provide NRG with financial support. In addition, NRG is expected to slow its project growth to lessen the need for external financing in the next few years. If the plan is carried out as proposed, we anticipate that NRG's internally generated cash, available credit and borrowing capabilities will be sufficient to meet its financing needs in addition to Xcel Energy equity support.

NRG and its subsidiaries have entered into a number of credit facilities. These credit facilities provided access to a total of $4.8 billion and DEM 204 million of funding at Dec. 31, 2001; at that date, borrowings of $2.9 billion were outstanding pursuant to these facilities. See further discussion in Notes 3 and 4 to the Financial Statements. In addition, NRG has filed a shelf registration to provide access to long-term debt financing, as discussed later.

Impact of NRG Credit Rating Downgrade NRG's unsecured credit rating is BBB- by Standard & Poor's and Baa3 by Moody's Investors Service. As noted previously, in December 2001 Moody's placed NRG's credit rating on review for potential downgrade. If Moody's subsequently downgraded NRG, many of the corporate guarantees and commitments that it currently has in place would need to be supported with letters of credit or cash collateral within five to 30 days. As of Dec. 31, 2001, the amount of collateral required if NRG were downgraded was approximately $960 million. Of the $960 million in collateral that could be required, approximately $200 million relates to NRG's guarantees of debt service reserve accounts required by some of its project-level financings, approximately $400 million relates to NRG's power marketing activities, and $360 million would be required to support the $2-billion NRG Finance Co. credit line. Because NRG places a maximum amount on all of its guarantees in place to support power marketing activities, and because of the relatively small number of margin accounts in place, even very large changes in market conditions would not have a material impact on the amount of collateral that would be required for NRG's power marketing in the event of a downgrade.

In the event of a downgrade, NRG would expect to meet the collateral obligations with cash on hand, available credit lines provided under the revolving line of credit, liquidity support from Xcel Energy and potentially from the issuance of debt into the capital markets. NRG's revolving line of credit is expected to be increased from $500 million to $1 billion in March 2002. In addition, NRG will maintain its $125-million letter of credit facility and plans to secure a funded $125-million credit facility for a total credit facility of $1.25 billion to be available in 2002.

The Contingent Equity Guarantee could increase to a maximum of $850 million by the end of 2002 as NRG further utilizes the capacity of the NRG Finance Co. credit line. Therefore, the amount of collateral required by the end of 2002 could increase to approximately $1.45 billion.

Registration Statements Xcel Energy's Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2001, Xcel Energy had approximately 346 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, 2001, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Registered securities available for issuance are as follows:

In February 2002, Xcel Energy filed a registration statement for the sale of $1 billion of common stock and debt securities, of which a currently estimated minimum of $400 million (representing 17.5 million shares) is planned to be issued as common stock in the first quarter of 2002 to provide financial support to NRG and pay down short-term debt. An expansion of the issuance could occur based on various market factors. See Note 19 to the Financial Statements. In addition, Xcel Energy has an effective shelf registration statement with the SEC under which $400 million of senior debt securities are available for issuance.

In April 2001, NSP-Minnesota filed a $600-million long-term debt shelf registration with the SEC.

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

In June 2001, NRG filed a shelf registration with the SEC to sell up to $2 billion in debt securities, common and preferred stock, warrants and other securities. NRG expects to use the net proceeds for general corporate purposes, which may include the financing and development of new facilities, working capital and debt reduction. NRG has approximately $1.5 billion remaining available under this shelf registration.

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.

WAYNE H. BRUNETTI
Chairman, President and Chief Executive Officer

EDWARD J. MCINTYRE
Vice President and Chief Financial Officer

XCEL ENERGY INC.
Minneapolis, Minnesota
February 21, 2002

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 December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2001. 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 years ended December 31, 2001 and 2000, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets and revenues of 45 percent and 18 percent for 2001, respectively, and total assets and revenues of 28 percent and 18 percent for 2000, respectively, of the related consolidated totals. We also did not audit the consolidated financial statements of Northern States Power Co., for the year ended December 31, 1999, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total revenues of 44 percent 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 subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 14 to the Consolidated Financial Statements, effective January 1, 2001 Xcel Energy Inc. and subsidiaries adopted Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activity," which changed its method of accounting for certain commodity contracts and other derivatives.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP
Minneapolis, Minnesota
February 21, 2002

REPORT 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 December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 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 audits. We conducted our audits 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 audits provide a reasonable basis for our opinion.

As discussed in Note 14 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" on January 1, 2001.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
February 21, 2002

To the Shareholders of Xcel Energy Inc.:

In our opinion, the consolidated statements of income, of common stockholders' equity and of cash flows for the year ended December 31, 1999 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 year ended December 31, 1999, 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.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
January 31, 2000, except as to Note 2,
which is as of February 22, 2000

(Thousands of dollars, except per share data)	*Year ended Dec. 31* 2001	2000	1999
OPERATING REVENUES:			
Electric utility	$ 6,394,737	$ 5,674,485	$ 4,921,612
Gas utility	2,052,651	1,468,880	1,141,429
Electric and gas trading	3,186,850	2,061,839	951,490
Nonregulated and other	3,176,896	2,203,878	710,871
Equity earnings from investments in affiliates	217,070	182,714	112,124
Total operating revenues	15,028,204	11,591,796	7,837,526
OPERATING EXPENSES:			
Electric fuel and purchased power – utility	3,171,660	2,580,723	1,967,335
Cost of gas sold and transported – utility	1,517,557	948,145	683,455
Electric and gas trading costs	3,097,601	2,020,482	947,144
Cost of sales – nonregulated and other	1,656,522	1,006,587	309,553
Other operating and maintenance expenses – utility	1,506,039	1,446,122	1,376,690
Other operating and maintenance expenses – nonregulated	807,955	636,280	276,146
Depreciation and amortization	949,200	792,395	679,851
Taxes (other than income taxes)	316,492	351,412	360,916
Special charges (see Note 2)	62,230	241,042	31,114
Total operating expenses	13,085,256	10,023,188	6,632,204
Operating income	1,942,948	1,568,608	1,205,322
Interest income and other nonoperating income – net of other expenses	72,161	18,639	1,134
INTEREST CHARGES AND FINANCING COSTS:			
Interest charges – net of amounts capitalized	782,399	657,305	414,277
Distributions on redeemable preferred securities of subsidiary trusts	38,800	38,800	38,800
Total interest charges and financing costs	821,199	696,105	453,077
Income before income taxes, minority interest and extraordinary items	1,193,910	891,142	753,379
Income taxes	336,723	304,865	179,673
Minority interest	72,508	40,489	2,773
Income before extraordinary items	784,679	545,788	570,933
Extraordinary items, net of income taxes of $4,807 and ($8,549), respectively (see Note 12)	10,287	(18,960)	–
Net income	794,966	526,828	570,933
Dividend requirements on preferred stock	4,241	4,241	5,292
Earnings available for common shareholders	$ 790,725	$ 522,587	$ 565,641
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
Basic	342,952	337,832	331,943
Diluted	343,742	338,111	332,054
EARNINGS PER SHARE – BASIC:			
Income before extraordinary items	$ 2.28	$ 1.60	$ 1.70
Extraordinary items (see Note 12)	0.03	(0.06)	–
Earnings per share	$ 2.31	$ 1.54	$ 1.70
EARNINGS PER SHARE – DILUTED:			
Income before extraordinary items	$ 2.27	$ 1.60	$ 1.70
Extraordinary items (see Note 12)	0.03	(0.06)	–
Earnings per share	$ 2.30	$ 1.54	$ 1.70

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*Year ended Dec. 31* 2001	2000	1999
OPERATING ACTIVITIES:			
Net income	$ 794,966	$ 526,828	$ 570,933
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	945,555	828,780	718,323
Nuclear fuel amortization	41,928	44,591	50,056
Deferred income taxes	11,190	62,716	18,161
Amortization of investment tax credits	(12,867)	(15,295)	(14,800)
Allowance for equity funds used during construction	(6,829)	3,848	(1,130)
Undistributed equity in earnings of unconsolidated affiliates	(124,277)	(87,019)	(67,926)
Gain on sale of nonregulated projects	–	–	(37,194)
Special charges – not requiring (using) cash	57,391	96,113	31,114
Conservation incentive accrual adjustments	(49,271)	19,248	71,348
Unrealized gain on derivative financial instruments	(9,804)	–	–
Extraordinary items – net of tax (see Note 12)	(10,287)	18,960	–
Change in accounts receivable	218,353	(443,347)	(113,521)
Change in inventories	(178,530)	21,933	(44,183)
Change in other current assets	340,478	(484,288)	(164,995)
Change in accounts payable	(325,946)	713,069	214,791
Change in other current liabilities	85,226	129,557	81,056
Change in other assets and liabilities	(193,264)	(27,969)	13,396
Net cash provided by operating activities	1,584,012	1,407,725	1,325,429
INVESTING ACTIVITIES:			
Nonregulated capital expenditures and asset acquisitions	(4,259,791)	(2,196,168)	(1,620,462)
Utility capital/construction expenditures	(1,105,989)	(984,935)	(1,178,663)
Allowance for equity funds used during construction	6,829	(3,848)	1,130
Investments in external decommissioning fund	(54,996)	(48,967)	(39,183)
Equity investments, loans, deposits and sales of nonregulated projects	154,845	(93,366)	(240,282)
Collection of loans made to nonregulated projects	6,374	17,039	81,440
Other investments – net	84,769	(36,749)	43,136
Net cash used in investing activities	(5,167,959)	(3,346,994)	(2,952,884)
FINANCING ACTIVITIES:			
Short-term borrowings – net	708,335	42,386	1,315,027
Proceeds from issuance of long-term debt	3,777,075	3,565,227	1,215,312
Repayment of long-term debt, including reacquisition premiums	(860,623)	(1,667,335)	(465,045)
Proceeds from issuance of common stock	133,091	116,678	95,317
Proceeds from NRG stock offering	474,348	453,705	–
Dividends paid	(518,894)	(494,992)	(492,456)
Net cash provided by financing activities	3,713,332	2,015,669	1,668,155
Effect of exchange rate changes on cash	(4,566)	360	–
Net increase in cash and cash equivalents	124,819	76,760	40,700
Cash and cash equivalents at beginning of year	216,491	139,731	99,031
Cash and cash equivalents at end of year	$ 341,310	$ 216,491	$ 139,731
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ 708,560	$ 610,584	$ 458,897
Cash paid for income taxes (net of refunds received)	$ 327,018	$ 216,087	$ 193,448

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 2001	2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 341,310	$ 216,491
Restricted cash	161,842	12,135
Accounts receivable – net of allowance for bad debts: $57,815 and $41,350, respectively	1,174,828	1,289,724
Accrued unbilled revenues	495,994	683,266
Materials and supplies inventories – at average cost	330,363	286,453
Fuel inventory – at average cost	250,043	116,990
Gas inventories – replacement cost in excess of LIFO: $11,331 and $106,790, respectively	126,563	77,390
Recoverable purchased gas and electric energy costs	52,583	283,167
Derivative instruments valuation – at market	59,790	–
Prepayments and other	318,046	162,458
Total current assets	3,311,362	3,128,074
Property, plant and equipment, at cost:		
Electric utility plant	16,099,655	15,304,407
Nonregulated property and other	8,388,261	5,348,976
Gas utility plant	2,493,028	2,376,868
Construction work in progress (utility amounts of $669,895 and $622,494, respectively)	3,682,633	915,486
Total property, plant and equipment	30,663,577	23,945,737
Less accumulated depreciation	(9,594,775)	(8,759,322)
Nuclear fuel – net of accumulated amortization: $1,009,855 and $967,927, respectively	96,315	86,499
Net property, plant and equipment	21,165,117	15,272,914
Other assets:		
Investments in unconsolidated affiliates	1,209,017	1,459,410
Notes receivable, including amounts from affiliates of $202,411 and $76,918, respectively	779,186	92,074
Nuclear decommissioning fund and other investments	695,070	732,908
Regulatory assets	502,442	524,261
Derivative instruments valuation – at market	179,683	–
Prepaid pension asset	378,825	225,134
Other	514,360	334,068
Total other assets	4,258,583	3,367,855
Total assets	$28,735,062	$21,768,843
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 682,207	$ 603,611
Short-term debt	2,224,812	1,475,072
Accounts payable	1,378,211	1,608,989
Taxes accrued	246,152	236,837
Dividends payable	130,845	128,983
Derivative instruments valuation – at market	83,122	–
Other	704,679	618,316
Total current liabilities	5,450,028	4,671,808
Deferred credits and other liabilities:		
Deferred income taxes	2,289,550	1,794,193
Deferred investment tax credits	184,148	198,108
Regulatory liabilities	483,942	494,566
Derivative instruments valuation – at market	57,575	–
Benefit obligations and other	703,836	588,288
Total deferred credits and other liabilities	3,719,051	3,075,155
Minority interest in subsidiaries	654,670	277,335
Capitalization (see Statements of Capitalization):		
Long-term debt	12,117,516	7,583,441
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 6)	494,000	494,000
Preferred stockholders' equity	105,320	105,320
Common stockholders' equity	6,194,477	5,561,784
Commitments and contingencies (see Note 15)		
Total liabilities and equity	$28,735,062	$21,768,843

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*Par Value*	*Premium*	*Retained Earnings*	*Shares Held by ESOP*	*Accumulated Other Comprehensive Income*	*Total Stockholders' Equity*
Balance at Dec. 31, 1998	$825,395	$2,197,058	$2,173,373	$(18,503)	$ (81,250)	$5,096,073
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)
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 *(a)*				6,897		6,897
Balance at Dec. 31, 1999	$838,193	$2,288,254	$2,253,800	$(11,606)	$ (78,421)	$5,290,220
Net income			526,828			526,828
Currency translation adjustments					(78,508)	(78,508)
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 *(a)*				6,989		6,989
Balance at Dec. 31, 2000	$852,085	$2,607,025	$2,284,220	$(24,617)	$(156,929)	$5,561,784
Net income			794,966			794,966
Currency translation adjustments					(56,693)	(56,693)
Cumulative effect of accounting change – net unrealized transition loss upon adoption of SFAS No. 133 (see Note 14)					(28,780)	(28,780)
After – tax net unrealized gains related to derivatives accounted for as hedges (see Note 14)					43,574	43,574
After – tax net unrealized losses on derivative transactions reclassified into earnings (see Note 14)					19,449	19,449
Unrealized loss – marketable securities					(75)	(75)
Comprehensive income for 2001						772,441
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(4,241)			(4,241)
Common stock			(516,515)			(516,515)
Issuances of common stock – net	12,418	120,673				133,091
Other			(27)			(27)
Gain recognized from NRG stock offering		241,891				241,891
Repayment of ESOP loan *(a)*				6,053		6,053
Balance at Dec. 31, 2001	$864,503	$2,969,589	$2,558,403	$(18,564)	$(179,454)	$6,194,477

(a) Did not affect cash flows

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*Dec. 31* *2001*	*2000*
LONG-TERM DEBT		
NSP-MINNESOTA DEBT		
First Mortgage Bonds, Series due:		
Dec. 1, 2001–2006, 3.65–4.1%	$ 11,225 *(a)*	$ 13,230 *(a)*
Oct. 1, 2001, 7.875%	–	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
March 1, 2011, variable rate, 1.8% at Dec. 31, 2001, and 5.05% at Dec. 31, 2000	13,700 *(b)*	13,700 *(b)*
March 1, 2019, variable rate, 2.04% at Dec. 31, 2001, and 4.25% at Dec. 31, 2000	27,900 *(b)*	27,900 *(b)*
Sept. 1, 2019, variable rate 1.76% and 2.04% at Dec. 31, 2001, and 4.36% and 4.61% at Dec. 31, 2000	100,000 *(b)*	100,000 *(b)*
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
Guaranty Agreements, Series due 2001–May 1, 2003, 5.375–7.4%	29,200 *(b)*	29,950 *(b)*
Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
City of Becker Revenue Bonds – Series due April 1, 2030, 1.85% at Dec. 31, 2001, and 5.1% at Dec. 31, 2000	69,000 *(b)*	69,000 *(b)*
Anoka County Bond – Series due Dec. 1, 2001–2008, 4.15–5%	16,090 *(a)*	17,990 *(a)*
Employee Stock Ownership Plan Bank Loans, due 2001–2007, variable rate	18,564	24,617
Other	390	194
Unamortized discount – net	(5,015)	(5,513)
Total	1,181,054	1,341,068
Less redeemable bonds classified as current (see Note 4)	141,600	141,600
Less current maturities	11,134	161,773
Total NSP-Minnesota long-term debt	$ 1,028,320	$ 1,037,695
PSCO DEBT		
First Mortgage Bonds, Series due:		
Jan. 1, 2001, 6%	$ –	$ 102,667
April 15, 2003, 6%	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 *(b)*	18,000 *(b)*
June 1, 2012, 5.5%	50,000 *(b)*	50,000 *(b)*
April 1, 2014, 5.875%	61,500 *(b)*	61,500 *(b)*
Jan. 1, 2019, 5.1%	48,750 *(b)*	48,750 *(b)*
March 1, 2022, 8.75%	147,840	147,840
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 Oct. 22, 2002–March 5, 2007, 6.45–7.65%	190,000	226,500
Other secured long-term debt, 13.25%	–	29,777
PSCCC Unsecured Medium-Term Notes, variable rate 7.4% at Dec. 31, 2000	–	100,000
Unamortized discount	(5,282)	(5,952)
Capital lease obligations, 11.2% due in installments through May 31, 2025	51,921	54,202
Total	1,482,229	1,752,784
Less current maturities	17,174	142,043
Total PSCo long-term debt	$ 1,465,055	$ 1,610,741
SPS DEBT		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ 100,000	$ 100,000
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	500,000	–
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 1.7% at Dec. 31, 2001 and 5.1% at Dec. 31, 2000	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Less funds held by Trustee	–	(168)
Unamortized discount	(1,425)	(126)
Total SPS long-term debt	$ 725,375	$ 226,506

See Notes to Consolidated Financial Statements

(Thousands of dollars)	*Dec. 31* *2001*	*2000*
LONG-TERM DEBT – CONTINUED		
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 *(a)*	18,600 *(a)*
Fort McCoy System Acquisition – due Oct. 31, 2030, 7%	963	996
Senior Notes – due Oct. 1, 2008, 7.64%	80,000	80,000
Unamortized discount	(1,475)	(1,562)
Total	313,088	313,034
Less current maturities	34	34
Total NSP-Wisconsin long-term debt	$ 313,054	$ 313,000
NRG DEBT		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 232,960	$ 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	350,000
July 15, 2006, 6.75%	340,000	–
April 1, 2011, 7.75%	350,000	–
April 1, 2031, 8.625%	500,000	–
May 16, 2006, 6.5%	284,440	–
NRG Finance Co. I LLC, due May 9, 2006, various rates	697,500	–
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	180,000	270,000
June 15, 2015, 8.842%	130,000	130,000
Dec. 15, 2024, 9.292%	300,000	300,000
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	463,500	488,750
Sept. 15, 2024, 9.479%	300,000	300,000
MidAtlantic – various, due Oct. 1, 2005, 3.56%	420,892	–
Sterling Luxembourg #3 Loan, due June 30, 2019, variable rate 7.86% at Dec. 31, 2001 and 2000	329,842	346,668
Flinders Power Finance Pty due, September 2012, various rates 8.56% at Dec. 31, 2001 and 7.58% at Dec. 31, 2000	74,886	83,820
Brazos Valley, due June 30, 2008, 3.44%	159,750	–
Camas Power Boiler, due June 30, 2007 and Aug. 1, 2007, 7.65% and 4.65%	20,909	–
Crockett Corp. LLP debt, due Dec. 31, 2014, 8.13%	234,497	245,229
Csepel Aramtermelo, due Oct. 2, 2017, 3.79% and 4.846%	169,712	–
Hsin Yu Energy Development, due November 2006–April 2012, 4–6.475%	89,964	–
LSP Batesville, due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	321,875	–
LSP Kendall Energy, due Sept. 1, 2005, 3.154%	499,500	–
McClain, due Dec. 31, 2005, 3.43%	159,885	–
NEO, due 2005–2008, 9.35%	23,956	27,185
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	62,408	65,762
PERC, due 2017–2018, 5.2%	33,220	–
Audrain Capital Lease Obligation, due Dec. 31, 2023, 10%	239,930	–
Saale Energie GmbH Schkopau Capital Lease, due May 2021, various rates	311,867	–
Various debt, due 2001–2007, 0.0–20.8%	148,121	33,738
Other	–	1,307
Total	8,344,614	3,796,845
Less current maturities	500,155	145,504
Total NRG long-term debt	$7,844,459	$3,651,341

See Notes to Consolidated Financial Statements

(Thousands of dollars)	Dec. 31 2001	2000
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, 1.8% and 4.95% at Dec. 31, 2001 and 2000	17,000	17,000
Viking Gas Transmission Co. Senior Notes – Series due:		
Oct. 31, 2008–Sept. 30, 2014, 6.65–8.04%	45,181	49,941
Various Eloigne Co. Affordable Housing Project Notes, due 2002–2027, 0.3–9.91%	47,856	51,309
Other	34,981	30,414
Total	157,018	160,664
Less current maturities	12,110	12,657
Total other subsidiaries long-term debt	$ 144,908	$ 148,007
XCEL ENERGY INC. DEBT		
Unsecured Senior Notes, due Dec. 1, 2010, 7%	$ 600,000	$ 600,000
Unamortized discount	(3,655)	(3,849)
Total Xcel Energy Inc. debt	$ 596,345	$ 596,151
Total long-term debt	$12,117,516	$ 7,583,441
MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS		
holding as their sole asset the junior subordinated deferrable debentures of:		
NSP-Minnesota, due 2037, 7.875%	$ 200,000	$ 200,000
PSCo, due 2038, 7.6%	194,000	194,000
SPS, due 2036, 7.85%	100,000	100,000
Total mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 494,000
CUMULATIVE PREFERRED STOCK – authorized 7,000,000 shares of $100 par value; outstanding shares: 2001, 1,049,800; 2000, 1,049,800		
$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, 99,800 shares	9,980	9,980
$4.56 series, 150,000 shares	15,000	15,000
Total	104,980	104,980
Premium on preferred stock	340	340
Total preferred stockholders' equity	$ 105,320	$ 105,320
COMMON STOCKHOLDERS' EQUITY		
Common stock – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2001, 345,801,028; 2000, 340,834,147	$ 864,503	$ 852,085
Premium on common stock	2,969,589	2,607,025
Retained earnings	2,558,403	2,284,220
Leveraged common stock held by ESOP – shares at cost: 2001, 783,162; 2000, 1,041,180	(18,564)	(24,617)
Accumulated other comprehensive income (loss)	(179,454)	(156,929)
Total common stockholders' equity	$ 6,194,477	$ 5,561,784

(a) Resource recovery financing
(b) Pollution control financing

See Notes to Consolidated Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Merger and Basis of Presentation On Aug. 18, 2000, 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. At Dec. 31, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. Xcel Energy owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering, and 82 percent until a secondary offering was completed in March 2001. See Note 19 to the Financial Statements for further discussion of potential changes in NRG ownership.

In addition to NRG, Xcel Energy's nonregulated subsidiaries include Utility Engineering (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (an international independent power producer).

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 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. Under this method, we record our proportionate share of pre-tax income as equity earnings from investments in affiliates. 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 record unbilled revenues for an estimate of the energy usage from the monthly meter-reading dates to the month's end.

Xcel Energy's utility subsidiaries have various rate 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 mechanism, which takes into account changes in energy costs and certain trading revenues and expenses that are shared with the customer. SPS' rates in Texas have fixed fuel factor and periodic fuel filing, reconciling and reporting requirements, which provide cost recovery. In New Mexico, SPS has recently reinstituted a monthly fuel and purchased power cost recovery factor. 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 Performance-Based Regulatory Plan, which results in an annual earnings test. 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 Beginning 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. Xcel Energy currently reports trading revenues separately from trading costs. 1999 results have been reclassified for consistency with the 2000 and 2001 presentation.

Xcel Energy's trading operations are conducted mainly by PSCo (electric) and e prime (gas). The results of the electric trading activity are initially recorded at PSCo. Pursuant to a Joint Operating Agreement, approved by the FERC as a part of the merger, the activity is then apportioned to the other operating utilities of Xcel Energy. Trading revenue and costs do not include the revenue and production costs associated with energy produced from generation assets or results from NRG. PSCo's trading results include the impacts of the ICA rate-sharing mechanism. For more information, see Notes 13 and 14 to the Financial Statements.

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 using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1 percent for the year ended Dec. 31, 2001, and 3.3 percent for the years ended Dec. 31, 2000 and 1999.

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 obtained for another future generating station in Colorado. PSCo is earning a return on these investments based on its weighted average cost of debt in accordance with a Colorado Public Utilities Commission (CPUC) rate order.

Allowance for Funds Used During Construction (AFDC) and Capitalized Interest 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 nonoperating income (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 for all Xcel Energy entities (including AFDC for utility companies) was approximately $56 million in 2001, $23 million in 2000 and $19 million in 1999.

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 16 to the Financial Statements.

Nuclear Fuel Expense Nuclear fuel expense, which is recorded as our nuclear generating plants use fuel, includes the cost of fuel used in the current period, as well as future disposal costs of spent nuclear fuel. In addition, nuclear fuel expense includes fees assessed by the U.S. Department of Energy (DOE) for NSP-Minnesota's portion of the cost of decommissioning 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 flow.

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 domestic subsidiaries, except NRG, file consolidated federal and combined and separate state income tax returns. Due to NRG's 2001 public equity offering, NRG and its subsidiaries will file a federal income tax return separate from Xcel Energy for the period March 13, 2001 through Dec. 31, 2001. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive taxable income of each company in the consolidated federal or combined state returns. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax basis 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 17 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 in common stockholders' equity. 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 Nonoperating 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 to reduce exposure to commodity price risk. The energy contracts are both financial- and commodity-based in the energy trading and energy nontrading operations. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps.

On Jan. 1, 2001, Xcel Energy adopted Statement of Financial Accounting Standard (SFAS) No. 133 – "Accounting for Derivative Instruments and Hedging Activity," as amended by SFAS No. 137 and SFAS No. 138 (collectively referred to as SFAS No. 133). For more information on the impact of SFAS No. 133, see Note 14 to the Financial Statements.

For further discussion of Xcel Energy's risk management and derivative activities, see Note 13 and Note 14 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 Items 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.

Restricted cash consists primarily of cash collateral for letters of credit issued in relation to project development activities and funds held in trust accounts to satisfy the requirements of certain debt agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

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 pricing.

Regulatory Accounting Our regulated utility subsidiaries account for certain income and expense items using SFAS No. 71 – "Accounting for the Effects of Certain Types of Regulation." Under SFAS No. 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 ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment.

Stock-Based Employee Compensation We have 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 awarded to certain employees, which is held until the restriction lapses or the stock is forfeited. For more information, see Note 9 to the Financial Statements.

NRG Development Costs As NRG develops projects, it expenses the development costs it incurs (for professional services, permits, etc.) 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. At Dec. 31, 2001, Xcel Energy had unamortized intangible assets of $166 million, including $69 million of goodwill, mainly at its nonregulated subsidiaries. The majority of these intangible assets are associated with energy contracts and will be amortized over the contract terms. Effective Jan. 1, 2002, Xcel Energy implemented SFAS No. 142. These amounts and all intangible assets and goodwill acquired in the future will be accounted for under the new accounting standard. The new accounting can be expected to initially increase earnings due to the elimination of amortization expense, but periodically causes reductions in earnings when impairment write-downs of goodwill and/or intangible assets are required.

Other assets also included deferred financing costs, net of amortization, of approximately $154 million at Dec. 31, 2001. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Reclassifications We reclassified certain items in the 1999 and 2000 income statements and the 2000 balance sheet to conform to the 2001 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, 1999. The reclassifications were primarily to conform the presentation of all consolidated Xcel Energy subsidiaries to a standard corporate presentation.

2. SPECIAL CHARGES

2001 – Restaffing During the fourth quarter of 2001, Xcel Energy expensed pretax special charges of $39 million, or 7 cents per share, for expected staff consolidation costs. The charges related to severance costs for utility operations resulting from the restaffing plans of several operating and corporate support areas of Xcel Energy relate primarily to nonbargaining positions. We accrued costs for 500 staff terminations, which are expected to occur, mainly in the first quarter of 2002, across all regions of Xcel Energy's service territory, but primarily in Minneapolis and Denver. As of Jan. 31, 2002, 239 of these terminations had occurred.

2001 – 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 had been recorded on a pay-as-you-go basis and, accordingly, PSCo recorded a regulatory asset in anticipation of obtaining future rate recovery of these transition 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 transition costs 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 appeal on the natural gas rate case. On Dec. 16, 1999, the Denver District Court affirmed the decision by the CPUC.

On July 2, 2001, the Colorado Supreme Court affirmed the District Court decision. Accordingly, PSCo has written off $23 million pretax, representing 4 cents per share, of regulatory assets related to deferred postemployment benefit costs as of June 30, 2001, since all means of regulatory recovery have been denied.

2000 – Merger Costs Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million. 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 $199 million, or 44 cents per share, associated with the costs of merging regulated operations. Of these pretax charges, $52 million related to one-time transaction-related costs incurred in connection with the merger of NSP and NCE and $147 million pertained to incremental costs of transition and integration activities associated with merging NSP and NCE to begin operations as Xcel Energy. The pretax charges also included $42 million, or 8 cents per share, of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy's nonregulated businesses. An allocation of the regulated portion of merger costs was made to utility operating companies using a basis consistent with prior regulatory filings, in proportion to expected merger savings by company and consistent with service company cost allocation methodologies utilized under the PUHCA requirements.

The transition costs include approximately $77 million for severance and related expenses associated with staff reductions of 721 employees, 706 of whom were released through Jan. 31, 2002. The staff reductions were nonbargaining 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.

Accrued Special Charges The following table summarizes activity related to accrued special charges in 2001 and 2000.

(Millions of dollars)	*Expensed 2000*	*Payments Through Dec. 31, 2000*	*Dec. 31, 2000 Liability**	*Expensed 2001*	*Payments 2001*	*Dec. 31, 2001 Liability**
Employee severance and related costs	$ 77	$ (29)	$ 48	$ 39	$ (50)	$ 37
Regulatory transition costs	12	(7)	5	–	(5)	–
Other transition and integration costs	58	(56)	2	–	(2)	–
Total accrued special charges	$ 147	$ (92)	$ 55	$ 39	$ (57)	$ 37

** Reported on the balance sheet in other current liabilities.*

1999 – EMI Goodwill In 1999, Xcel Energy expensed pretax 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.

1999 – Loss on Marketable Securities During 1999, Xcel Energy expensed pretax 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 in February 2000, 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, 2001 and 2000 is:

(Millions of dollars, except interest rates)	*2001*	*2000*
Notes payable to banks	$ 835	$ 20
Commercial paper	1,390	1,455
Total short-term debt	$2,225	$1,475
Weighted average interest rate at year end	3.41%	6.48%

Bank Lines of Credit and Compensating Bank Balances At Dec. 31, 2001, we and our subsidiaries had approximately $6.9 billion and DEM 203.6 million in credit facilities with several banks. We pay for these lines of credit with a combination of fee payments and compensating balances.

	Period Beginning	*Term*	*Credit Line*
Xcel Energy	November 2001	364 days	$ 400 million
Xcel Energy	November 2000	5 years	$ 400 million
NSP-Minnesota	August 2001	364 days	$ 300 million
PSCo	June 2001	364 days	$ 600 million
SPS	February 2001	364 days	$ 300 million
NRG total			$ 4.8 billion and DEM 203.6 million
Other subsidiaries	various	various	$ 118 million

The lines of credit for companies other than NRG provide short-term financing in the form of bank loans and letters of credit, but their primary purpose is support for commercial paper borrowings. At Dec. 31, 2001, there were no loans outstanding under these lines of credit. The borrowing rate under these lines of credit is based on the 90-day London Interbank Offered Rate (LIBOR), a euro dollar rate margin, and the amount of money borrowed. The rate that would have applied at Dec. 31, 2001, if we had loans outstanding, would have been between 2.18 percent and 2.505 percent.

At Dec. 31, 2001, NRG had three credit facilities for short-term financing:

– a $500-million recourse revolving credit facility under a commitment fee arrangement that matures in March 2002. This facility provided short-term financing in the form of bank loans. At Dec. 31, 2001, NRG had $170 million outstanding under this facility. In March 2002, the revolving credit facility will terminate. During the period ended Dec. 31, 2001, the facility bore interest at a floating rate based on LIBOR and prime rates throughout the period and had a weighted average interest rate of 5.89 percent,
– a $40-million revolving credit facility that matures in March 2002. This is a facility of NRG's South Central project and is non-recourse to NRG. At Dec. 31, 2001, NRG South Central had $40 million outstanding under this facility at 4.46 percent and
– a $600-million unsecured term loan facility, which terminates on June 21, 2002. At Dec. 31, 2001, the aggregate amount outstanding under this facility was $600 million at a weighted average interest rate of 3.94 percent.

NRG's other credit facilities are used for long-term financing. See discussion in Note 4 to the Financial Statements.

4. LONG-TERM DEBT

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

There are annual sinking-fund requirements in our utility subsidiaries' first mortgage indentures, in the amounts necessary to redeem 1 to 6.7 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 $1.7 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 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. Because of the terms that allow the holders to redeem these bonds on short notice, we include them in the current portion of long-term debt reported under current liabilities on the balance sheets.

NRG has several credit facilities used for long-term financing:

(Currency in thousands) *Facility*	*Available Line of Credit*	*Recourse to NRG*	*End Date*	*Outstanding Dec. 31, 2001*	*Rate at Dec. 31, 2001*
REVOLVING LINES OF CREDIT:					
NRG Finance Co. I LLC	$2,000,000	Yes	May 2009	$ 697,500	4.83%
TERM LOAN FACILITIES:					
MidAtlantic	$580,000	No	November 2005	$ 420,892	3.56%
LSP Kendall Energy	$554,200	No	September 2005	$ 499,500	3.15%
Csepel	$78,500 and DEM 203,600	No	October 2017	$ 169,712	3.79–4.85%
Brazos Valley	$180,000	No	June 2008	$ 159,750	3.44%
McClain	$296,000	No	December 2005	$ 159,885	3.43%

The NRG Finance Co. I LLC facility is used to finance the acquisition, development and construction of power generating plants located in the United States and to finance the acquisition of turbines for such facilities. The facility is nonrecourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility.

On March 13, 2001, NRG completed the sale of 11.5 million "equity units" for an initial price of $25 per unit. Each equity unit initially consists of a $25 NRG senior debenture (6.5 percent notes due May 16, 2006) and an obligation to acquire shares of NRG common stock no later than May 18, 2004, at a price ranging from $27.00 to $32.94 per share.

The $240-million NRG senior notes due Nov. 1, 2013, are Remarketable or Redeemable Securities (ROARS). At certain dates the notes must either be tendered to and purchased by Credit Suisse Financial Products or redeemed by NRG at prices discussed in the indenture. The notes are unsecured debt that rank senior to all of NRG's existing and future subordinated indebtedness.

NRG's $250-million issue of 8.7 percent ROARS due March 15, 2005, may be remarketed by Bank of America, N.A. at a fixed rate of interest through the maturity date or at a floating rate of interest for up to one year and then at a fixed rate of interest through 2020.

Maturities and sinking fund requirements of long-term debt are:

2002	$ 682 million
2003	$ 719 million
2004	$ 335 million
2005	$ 1,140 million
2006	$ 1,832 million

5. PREFERRED STOCK

At Dec. 31, 2001, we had six series of preferred stock outstanding, which were callable at our option at prices ranging from $102.00 to $103.75 per share plus accrued dividends.

The holders of our $3.60 series preferred stock are entitled to three votes for each share held. The holders of our other preferred stocks are entitled to one vote per share. While dividends payable on the preferred stock of any series outstanding is in arrears in an amount equal to four quarterly dividends, the holders of preferred stocks, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the board of directors and the holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of our subsidiaries also authorize the issuance of preferred shares; however, at this time there are no such shares outstanding. This chart shows data for first- and second-tier subsidiaries:

	Preferred Shares Authorized	*Par Value*	*Preferred Shares Outstanding*
Cheyenne Light, Fuel & Power Co.	1,000,000	$ 100.00	None
Southwestern Public Service Co.	10,000,000	$ 1.00	None
Public Service Co. of Colorado	10,000,000	$ 0.01	None
NRG Energy, Inc.	200,000,000	$ 0.01	None
PS Colorado Credit Corp.	25,000,000	$ 1.00	None

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 NSP Financing I's option 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.

The manditorily redeemable preferred securities of subsidiary trusts are consolidated in Xcel Energy's Consolidated Balance Sheets. Distributions paid to preferred security holders are reflected as a financing cost in the Consolidated Statements of Income along with interest charges.

7. JOINT PLANT OWNERSHIP

The investments by Xcel Energy's subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2001, are:

(Thousands of dollars)	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NSP-MINNESOTA:				
Sherco Unit 3	$ 609,382	$ 271,874	$ 1,158	59.0
PSCO:				
Hayden Unit 1	$ 84,032	$ 37,664	$ 223	75.5
Hayden Unit 2	79,197	40,864	63	37.4
Hayden Common Facilities	28,044	2,715	156	53.1
Craig Units 1 & 2	59,799	30,593	–	9.7
Craig Common Facilities Units 1, 2 & 3	26,052	8,816	–	6.5–9.7
Transmission Facilities, including Substations	84,760	28,689	125	42.0–73.0
Total PSCo	$ 361,884	$ 149,341	$ 567	

(Thousands of dollars) continued	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NRG:				
McClain	$ 276,589	$ 3,836	$ –	77.0
Big Cajun II Unit 3	177,359	7,838	2,249	58.0
Conemaugh	60,237	1,497	695	3.7
Keystone	51,906	1,291	1,022	3.7
Total NRG	$ 566,091	$ 14,462	$ 3,966	

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 operating expenses for Sherco 3 is included in the applicable utility components of operating expenses. PSCo's assets include approximately 320 megawatts of jointly owned generating capacity. PSCo's share of operating expenses and construction expenditures are included in the applicable utility components of operating expenses. NRG's share of operating expenses and construction expenditures are included in the applicable nonregulated components of operating expenses. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

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:

	2001	*2000*	*1999*
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	2.5%	5.8%	2.1%
Life insurance policies	(1.9)%	(2.4)%	(2.3)%
Tax credits recognized	(6.6)%	(10.2)%	(6.0)%
Equity income from unconsolidated affiliates	(1.7)%	(2.3)%	(5.5)%
Income from foreign consolidated affiliates	(0.8)%	(0.4)%	0.0%
Regulatory differences – utility plant items	1.8%	2.3%	1.9%
Deferred tax expense on Yorkshire investment	0.0%	2.3%	0.0%
Nondeductible merger costs	0.0%	2.9%	0.0%
Other – net	0.1%	1.8%	(1.3)%
Effective income tax rate including extraordinary items	28.4%	34.8%	23.9%
Effective income tax rate excluding extraordinary items	28.0%	35.8%	23.9%

Income taxes comprise the following expense (benefit) items:

(Thousands of dollars)			
Current federal tax expense	$ 373,891	$ 205,718	$ 175,461
Current state tax expense	26,927	63,428	26,949
Current foreign tax expense	6,510	(625)	4,040
Current federal tax credits	(66,179)	(71,270)	(30,137)
Deferred federal tax expense	(24,114)	103,258	27,380
Deferred state tax expense	18,702	12,547	(2,352)
Deferred foreign tax expense	13,969	7,104	(6,868)
Deferred investment tax credits	(12,983)	(15,295)	(14,800)
Income tax expense excluding extraordinary items	336,723	304,865	179,673
Tax expense (benefit) on extraordinary items	4,807	(8,549)	–
Total income tax expense	$ 341,530	$ 296,316	$ 179,673

Xcel Energy management intends to reinvest the earnings from NRG's foreign operations to the extent the earnings are subject to current U.S. income taxes. 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 $345 million and $238 million at Dec. 31, 2001 and 2000. 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 management also intends to reinvest the earnings of the Argentina operations of Xcel Energy International and, therefore, has not provided deferred taxes for the effects of the currency devaluation discussed in Note 15 to the Financial Statements. However, as a result of management's revised strategic plan for Yorkshire Power to begin repatriation of earnings to the United States, Xcel Energy provided deferred taxes of $20 million on unremitted earnings of $55 million at Dec. 31, 2000. Due to the sale of the majority of its interest in Yorkshire Power during 2001, Xcel Energy now accounts for its remaining investment under the cost method.

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

(Thousands of dollars)	*2001*	*2000*
Deferred tax liabilities:		
Differences between book and tax basis of property	$2,195,323	$1,754,928
Regulatory assets	155,587	168,380
Partnership income/loss	53,955	70,266
Unrealized gains and losses on mark-to-market transactions	45,701	411
Tax benefit transfer leases	14,765	18,839
Other	73,437	97,852
Total deferred tax liabilities	$2,538,768	$2,110,676
Deferred tax assets:		
Differences between book and tax basis of contracts	$ 82,972	$ –
Deferred investment tax credits	72,345	76,133
Regulatory liabilities	66,507	88,817
Foreign tax loss carryforwards	23,630	25,063
Employee benefits and other accrued liabilities	(16,559)	14,675
Other	87,387	62,053
Total deferred tax assets	$ 316,282	$ 266,741
Net deferred tax liability	$2,222,486	$1,843,935

9. COMMON STOCK AND INCENTIVE STOCK PLANS

Incentive Stock Plans Xcel Energy and some of its 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 options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables below include awards made by us and some of our predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

Stock Options and Performance Awards at Dec. 31:

	2001		*2000*		*1999*	
(Thousands)	*Awards*	*Average Price*	*Awards*	*Average Price*	*Awards*	*Average Price*
Outstanding at beginning of year	14,259	$25.35	8,490	$25.12	6,156	$26.15
Granted	2,581	25.98	6,980	25.31	2,545	22.64
Exercised	(1,472)	23.00	(453)	20.33	(90)	18.72
Forfeited	(142)	27.08	(704)	25.70	(111)	30.10
Expired	(12)	24.07	(54)	22.62	(10)	25.64
Outstanding at end of year	15,214	25.65	14,259	25.35	8,490	25.12
Exercisable at end of year	7,154	24.78	8,221	24.46	5,301	25.84

		Range of Exercise Prices	
At Dec. 31, 2001	$16.60 to $21.75	$21.76 to $27.99	$28.00 to $31.01
Options outstanding:			
Number outstanding	2,544,374	11,261,229	1,408,857
Weighted average remaining contractual life (years)	6.8	8.0	6.5
Weighted average exercise price	$19.87	$26.33	$30.66
Options exercisable:			
Number exercisable	2,334,841	3,459,896	1,359,376
Weighted average exercise price	$19.86	$25.79	$30.67

Certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally from two to three years from the date of grant. 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 21,774 restricted shares in 2001, 58,690 restricted shares in 2000 and 52,688 restricted shares in 1999. 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 our 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 No. 123 method of accounting, earnings would have been reduced by approximately 1 cent per share for 2001, 2 cents per share for 2000 and 1 cent per share for 1999.

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:

	2001	*2000*	*1999*
Expected option life	3–5 years	3–5 years	5–10 years
Stock volatility	18%	15%	15–21%
Risk-free interest rate	3.8–4.8%	5.3–6.5%	4.7–6.4%
Dividend yield	4.9–5.8%	5.4–7.5%	5.4%

Dividend Restrictions The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Xcel Energy has outstanding preferred stock. It could have paid nearly $2 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 $825 million in additional cash dividends on common stock at Dec. 31, 2001.

Stockholder Protection Rights Agreement On June 28, 2001, Xcel Energy adopted a Stockholder Protection Rights Agreement. Each share of Xcel Energy's common stock includes one shareholder protection right. Under the agreement's principal provision, if any person or group acquires 15 percent or more of Xcel Energy's outstanding common stock, all other shareholders of Xcel Energy would be entitled to buy, for the exercise price of $95 per right, common stock of Xcel Energy having a market value equal to twice the exercise price, thereby substantially diluting the acquiring person's or group's investment. The rights may cause substantial dilution to a person or group that acquires 15 percent or more of Xcel Energy's common stock. The rights should not interfere with a transaction that is in the best interests of Xcel Energy and its shareholders because the rights can be redeemed prior to a triggering event for $0.01 per right.

10. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 44 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2001, NSP-Minnesota and NSP-Wisconsin had 2,563 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 1,979 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 742 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, 2001 and 2000, for Xcel Energy plans on a combined basis is presented in the following table.

(Thousands of dollars)	*2001*	*2000*
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	$2,254,138	$2,170,627
Service cost	57,521	59,066
Interest cost	172,159	172,063
Acquisitions	–	52,800
Plan amendments	2,284	2,649
Actuarial (gain) loss	108,754	1,327
Benefit payments	(185,670)	(204,394)
Obligation at Dec. 31	$2,409,186	$2,254,138
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	$3,689,157	$3,763,293
Actual return on plan assets	(235,901)	91,846
Acquisitions	–	38,412
Benefit payments	(185,670)	(204,394)
Fair value of plan assets at Dec. 31	$3,267,586	$3,689,157
FUNDED STATUS AT DEC. 31		
Net asset	$ 858,400	$1,435,019
Unrecognized transition (asset) obligation	(9,317)	(16,631)
Unrecognized prior-service cost	242,313	228,436
Unrecognized (gain) loss	(712,571)	(1,421,690)
Prepaid pension asset recorded	$ 378,825	$ 225,134
SIGNIFICANT ASSUMPTIONS		
Discount rate for year-end valuation	7.25%	7.75%
Expected average long-term increase in compensation level	4.5%	4.5%
Expected average long-term rate of return on assets	9.5%	8.5–10.0%

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

(Thousands of dollars)	*2001*	*2000*	*1999*
Service cost	$ 57,521	$ 59,066	$ 63,674
Interest cost	172,159	172,063	154,619
Expected return on plan assets	(325,635)	(292,580)	(259,074)
Curtailment	1,121	–	–
Amortization of transition asset	(7,314)	(7,314)	(7,314)
Amortization of prior-service cost	20,835	19,197	17,855
Amortization of net gain	(72,413)	(60,676)	(40,217)
Net periodic pension cost (credit) under SFAS No. 87	$(153,726)	$(110,244)	$ (70,457)
Credits not recognized due to effects of regulation	76,509	49,697	36,469
Net benefit cost (credit) recognized for financial reporting	$ (77,217)	$ (60,547)	$ (33,988)

NRG also offers other noncontributory, defined benefit pension plans that are sponsored by NRG and its affiliates. For the year ended Dec. 31, 2001, the total assets of such plans were $16 million and benefit obligations were $37 million. The net recorded pension liabilities for these plans were $19 million and annual pension costs were $4 million.

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 $29 million in 2001, $23 million in 2000 and $21 million in 1999.

Xcel Energy has a leveraged employee stock ownership plan (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 it realizes 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 10.5 million shares of Xcel Energy common stock at the end of 2001, 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. Xcel Energy excluded the following uncommitted leveraged ESOP shares from earnings per share calculations: 0.9 million in 2001, 0.7 million in 2000 and 0.5 million in 1999.

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 retiring after 1999.

In conjunction with the 1993 adoption of SFAS No. 106 – "Employers' Accounting for Postretirement Benefits Other Than Pension," Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation 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 No. 106. PSCo transitioned to full accrual accounting for SFAS No. 106 costs between 1993 and 1997, consistent with the accounting requirements for rate-regulated enterprises. The Colorado jurisdictional SFAS No. 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 No. 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 No. 106 costs. SPS is required to fund SFAS No. 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo and Cheyenne are required to fund SFAS No. 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 No. 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, 2001 and 2000, for all Xcel Energy postretirement health care plans is presented in the following table.

(Thousands of dollars)	*2001*	*2000*
CHANGE IN BENEFIT OBLIGATION		
Obligation at Jan. 1	$576,727	$533,458
Service cost	6,160	5,679
Interest cost	46,579	43,477
Acquisitions	3,212	16,445
Plan participants' contributions	3,517	4,358
Plan amendments	(278)	–
Actuarial (gain) loss	100,386	10,501
Benefit payments	(48,848)	(37,191)
Obligation at Dec. 31	$687,455	$576,727
CHANGE IN FAIR VALUE OF PLAN ASSETS		
Fair value of plan assets at Jan. 1	$223,266	$201,767
Actual return on plan assets	(3,701)	10,069
Plan participants' contributions	3,517	4,358
Employer contributions	68,569	44,263
Benefit payments	(48,848)	(37,191)
Fair value of plan assets at Dec. 31	$242,803	$223,266
FUNDED STATUS AT DEC. 31		
Net obligation	$444,652	$353,461
Unrecognized transition asset (obligation)	(186,099)	(202,871)
Unrecognized prior-service cost	12,812	13,789
Unrecognized gain (loss)	(134,225)	(11,126)
Accrued benefit liability recorded	$137,140	$153,253
SIGNIFICANT ASSUMPTIONS:		
Discount rate for year-end valuation	7.25%	7.75%
Expected average long-term rate of return on assets	9.0%	8.0–9.5%

The assumed health care cost trend rate for 2001 is approximately 8.0 percent, decreasing gradually to 5.5 percent in 2007 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 $72.3 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $5.8 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 $60.2 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $4.7 million.

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

(Thousands of dollars)	*2001*	*2000*	*1999*
Service cost	$ 6,160	$ 5,679	$ 4,680
Interest cost	46,579	43,477	35,583
Expected return on plan assets	(18,920)	(17,902)	(15,003)
Amortization of transition obligation	16,771	16,773	17,461
Amortization of prior-service cost (credit)	(1,235)	(1,211)	(1,803)
Amortization of net loss (gain)	1,457	915	(5)
Net periodic postretirement benefit costs under SFAS No. 106	50,812	47,731	40,913
Additional cost recognized due to effects of regulation	3,738	6,641	4,029
Net cost recognized for financial reporting	$ 54,550	$ 54,372	$ 44,942

11. EQUITY INVESTMENTS AND ASSET ACQUISITIONS

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 because the ownership structure prevents Xcel Energy from exercising a controlling influence over the operating and financial policies of the projects. 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.

Name	*Geographic Area*	*Dec. 31, 2001 Economic Interest*
Loy Yang Power A	Australia	25.37%
Enfield Energy Centre	Europe	25.00%
Gladstone Power Station	Australia	37.50%
COBEE (Bolivian Power Co. Ltd.)	South America	49.45%
MIBRAG GmbH	Europe	50.00%
Cogeneration Corp. of America	USA	20.00%
Schkopau Power Station	Europe	41.90%
West Coast Power	USA	50.00%
Energy Developments Limited	Australia	25.10%
Scudder Latin American Power	Latin America	25.00%
Lanco Kondapalli Power	India	30.00%
ECK Generating	Czech Republic	44.50%
Rocky Road Power	USA	50.00%
Mustang	USA	25.00%
Sabine River Works Cogeneration	USA	50.00%
Quixx Linden L.P.	USA	50.00%
Borger Energy L.P.	USA	45.00%
Denver City Energy Associates, L.P.	USA	50.00%
Various independent power production facilities	USA	9–70%
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

(Millions of dollars)	*2001*	*2000*	*1999*
Operating revenues	$3,583	$4,664	$4,087
Operating income	$ 442	$ 464	$ 516
Net income	$ 422	$ 447	$ 290
Xcel Energy's equity earnings of unconsolidated affiliates	$ 217	$ 183	$ 112

FINANCIAL POSITION

(Millions of dollars)	*2001*	*2000*
Current assets	$1,478	$ 1,590
Other assets	7,396	10,939
Total assets	$8,874	$12,529

FINANCIAL POSITION CONTINUED

(Millions of dollars)	*2001*	*2000*
Current liabilities	$ 1,229	$ 1,833
Other liabilities	4,841	6,806
Equity	2,804	3,890
Total liabilities and equity	$ 8,874	$12,529
Xcel Energy's share of undistributed retained earnings	$ 93	$ 96

Yorkshire Power During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power to Innogy Holdings plc. As a result of this sales agreement, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001. In April 2001, Xcel Energy closed the sale of Yorkshire Power. Xcel Energy has retained an interest of approximately 5.25 percent in Yorkshire Power to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Xcel Energy received approximately $366 million for the sale, which approximated the book value of Xcel Energy's investment.

NRG Asset Acquisitions During the year ended Dec. 31, 2001, NRG completed numerous acquisitions of project assets and related liabilities. These acquisitions have been recorded using the purchase method of accounting. Accordingly, the purchase prices of each acquisition have been preliminarily allocated to assets acquired and liabilities assumed based on their estimated fair values at the various dates of acquisition. These estimates will be adjusted based upon completion of certain procedures, including third party valuations. Operations of the acquired projects have been included in Xcel Energy's results of operations since the respective dates of each acquisition.

The following is a summary of the projects acquired in 2001:

Project Acquired	*Total Plant Megawatt (MW)*	*NRG Ownership*	*Operations*
LS Power (USA)	5,633 (1,697 in operation or under construction)	100%	
Indeck (USA)	2,255 (402 in operation)	100%	
Conectiv (USA)	4,340	100% of 918 MW; 4% of remainder	
Termo Rio (Brazil)	1,040	50%	Operations beginning in 2004
Schkopau (Germany)	960	Increased from 21% to 42%	
Audrain (USA)	640	100%	
Fort Bend (USA)	633	100%	Operations beginning in 2003
Csepel (Hungary)	505	100%	
McClain (USA)	500	77%	
Cogentrix (USA)	837	100%	
MIBRAG (Germany)	233	Increased from 33% to 50%	
Various other	372 in operation	various	

The respective purchase prices of these 2001 acquisitions have been allocated to the net assets of the acquired NRG projects as follows:

(Thousands of dollars)	
Current assets	$ 307,654
Property, plant and equipment	4,173,509
Noncurrent portion of notes receivable	736,041
Current portion of long-term debt assumed	(61,268)
Other current liabilities	(99,666)
Long-term debt assumed	(1,586,501)
Deferred income taxes	(149,988)
Other long-term liabilities	(202,411)
Other noncurrent assets and liabilities	(181,473)
Total purchase price	2,935,897
Less cash balances acquired	(122,780)
Net purchase price	$ 2,813,117

12. ELECTRIC UTILITY RESTRUCTURING – SPS

In the second quarter of 2000, SPS discontinued regulatory accounting under SFAS No. 71 for the generation portion of its business due to the issuance of a written order by the Public Utility Commission of Texas (PUCT) in May 2000, addressing the implementation of electric utility restructuring. SPS' transmission and distribution business continued to meet the requirements of SFAS No. 71, as that business was expected to remain regulated. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs totaling approximately $19.3 million. This resulted in an after-tax extraordinary charge of approximately $13.7 million. 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 first mortgage bonds. The first mortgage bonds were defeased to facilitate the legal separation of generation, transmission and distribution assets, which was expected to eventually occur in 2001 under restructuring requirements in effect in 2000.

In March 2001, the state of New Mexico enacted legislation that amended its Electric Utility Restructuring Act of 1999 and delayed customer choice until 2007. SPS has requested recovery of its costs incurred to prepare for customer choice in New Mexico. A decision on this and other matters is pending before the New Mexico Public Regulation Commission. SPS expects to receive future regulatory recovery of these costs.

In June 2001, the governor of Texas signed legislation postponing the deregulation and restructuring of SPS until 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition to begin in Texas in January 2002. Under the amended legislation, prior PUCT orders issued in connection with the restructuring of SPS are considered null and void. SPS' restructuring and rate unbundling proceedings in Texas have been terminated. In addition, under the legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before Sept. 1, 2001, to comply with SB-7. As required, SPS filed an application during the fourth quarter of 2001, requesting a rate rider to recover these costs incurred preparing for customer choice. These proceedings are pending.

As a result of these recent legislative developments, SPS reapplied the provisions of SFAS No. 71 for its generation business during the second quarter of 2001. More than 95 percent of SPS' retail electric revenues are from operations in Texas and New Mexico. Because of the delays to electric restructuring passed by Texas and New Mexico, SPS' previous plans to implement restructuring, including the divestiture of generation assets, have been abandoned. Accordingly, SPS will now continue to be subject to rate regulation under traditional cost-of-service regulation, consistent with its past accounting and ratemaking practices for the foreseeable future (at least until 2007). In the second quarter of 2001, SPS did not restore any regulatory assets or other costs previously written off due to the uncertainty of various regulatory issues, including transition plans to address future rate recovery of SPS' restructuring costs.

During the fourth quarter of 2001, SPS completed a $500-million medium-term debt financing, with the proceeds used to reduce short-term borrowings that had resulted from the 2000 defeasance. In its regulatory filings and communications, SPS has proposed to amortize its defeasance costs over the five-year life of the refinancing, consistent with historical ratemaking, and has requested incremental rate recovery of $25 million of other restructuring costs in Texas and New Mexico, as previously discussed. These nonfinancing restructuring costs have been deferred and will be amortized in the future consistent with rate recovery. Management believes it will be allowed full recovery of its prudently incurred costs. Based on these fourth-quarter events and the corresponding reduced uncertainty surrounding the financial impacts of the delay in restructuring, SPS restored certain regulatory assets totaling $17.6 million as of Dec. 31, 2001, and reported related after-tax extraordinary income of $11.8 million, or 3 cents per share. Regulatory assets previously written off in 2000 were restored only for items currently being recovered in rates and items where future rate recovery is considered probable.

13. FINANCIAL INSTRUMENTS

FAIR VALUES

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

	2001		2000	
(Thousands of dollars)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 486,270	$ 494,000	$ 481,270
Long-term investments	$ 619,976	$ 620,703	$ 625,616	$ 624,989
Notes receivable, including current portion	$ 782,079	$ 782,079	$ 99,557	$ 99,557
Long-term debt, including current portion	$12,799,723	$12,788,749	$8,187,052	$8,131,139

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 notes receivable is based on expected future cash flows discounted at market interest rates. The balance in notes receivable consists primarily of fixed and variable rate notes (interest rates ranging from 4.75 percent to 19.5 percent and maturities ranging from 2001 to 2024). Notes receivable include a $319-million direct financing lease related to a long-term sales agreement for NRG's Schkopau project, and other notes related to projects at NRG that are generally secured by equity interests in partnerships and joint ventures. 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, 2001 and 2000. 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 had the following guarantees outstanding as of Dec. 31, 2001 (in millions of dollars):

Guarantor	*Guarantee Amount*	*Nature of Guarantee*
NRG	$ 721.7	Obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	343.1	Guarantee performance and payment of surety bonds for itself and its subsidiaries.
Various Subsidiaries	336.9	Guarantee performance and payment of surety bonds for those subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	270.7	Guarantees made to facilitate e prime's natural gas acquisition, marketing and trading operations.
Xcel Energy	60.0	Guarantee on the payments on notes issued by Guardian Pipeline LLC, of which Viking Gas Transmission Co. is one of three partners. The guarantee will terminate on the in-service date of the pipeline, which is expected to be March 2003.
Xcel Energy	28.5	Three guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements.
Xcel Energy	25.0	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, has constructed a 230-megawatt, cogeneration facility at a Phillips Petroleum site near Borger, Texas. The guarantee will remain in effect until no later than July 2003.
SPS	22.9	Guarantee for certain obligations of a customer in connection with an agreement for the sale of electric power. These obligations relate to the construction of certain utility property that, in the event of default by the customer, would revert to SPS.
Xcel Energy	17.9	Guarantees related to energy conservation projects in which Planergy 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 2024.
Xcel Energy	17.0	Guarantees payments for XERS Inc., a nonregulated subsidiary of Xcel Energy, under a Master Power Purchase and Sale Agreement and a Qualified Scheduling Entity Services Agreement. This guarantee was terminated and replaced with a $10-million guarantee in January 2002.
NSP-Minnesota	11.6	NSP-Minnesota sold a portion of its 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. Based on prior collection experience of these loans, losses under the loan guarantees, if any, are not believed to have a material impact on the results of operations.
Xcel Energy	5.0	Guarantee on behalf of BNP Paribas in connection with a letter of credit provided by BNP Paribas at the request of SPS. The letter of credit is required to indemnify former SPS board of directors.
Xcel Energy	4.5	Guarantee for e prime Energy Marketing, Inc.'s performance of obligations under a supply agreement and for payments of energy and capacity transactions.
Xcel Energy	3.0	Guarantee resulting from noncompletion of certain milestone achievements within required dates in connection with the Quixx Linden cogeneration plant. The milestones have been achieved as of December 2001. The guarantee is required to remain six months upon completion of these milestones. Therefore, the guarantee will be released June 2002, assuming contract requirements are met.
Xcel Energy	4.1	Combination of guarantees benefiting various Xcel Energy subsidiaries.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

The following discussion briefly describes the derivatives of Xcel Energy and its subsidiaries and discloses the respective fair values at Dec. 31, 2001. For more detailed information regarding derivative financial instruments and the related risks, see Note 14 to the Financial Statements.

Interest Rate Swaps As of Dec. 31, 2001, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $2.5 billion. The fair value of the swaps as of Dec. 31, 2001 was a liability of approximately $92 million.

As of Dec. 31, 2000, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $598 million. The fair value of the swaps as of Dec. 31, 2000 was a liability of approximately $36 million.

Electric Trading Operations Xcel Energy participates in the trading of electricity as a commodity. This trading includes forward contracts, futures and options. Xcel Energy makes purchases and sales at existing market points or combines purchases with available transmission to make sales at other market points. Options and hedges are used to either minimize the risks associated with market prices, or to profit from price volatility related to our purchase and sale commitments.

Xcel Energy has recorded its physical trading transactions on total contract purchases and total contract sales known as the gross accounting method. All financial derivative contracts and contracts that do not include physical delivery are recorded at the amount of the gain or loss received from the contract. The mark-to-market adjustments for these transactions are appropriately reported in the Consolidated Statement of Income in Electric and Gas Trading Revenues.

The fair value of Xcel Energy's trading contracts as of Dec. 31, 2001 is as follows:

(Millions of dollars)	*Total Fair Value*
Fair value of trading contracts outstanding at Jan. 1, 2001	$ 8.6
Contracts realized or settled during 2001	(87.0)
Fair value of trading contract additions and changes during the year	96.2
Fair value of contracts outstanding at Dec. 31, 2001*	$ 17.8

** Amounts do not include the impact of ratepayer sharing in Colorado.*

The future maturities of Xcel Energy's trading contracts are as follows:

(Millions of dollars) *Source of Fair Value*	*Maturity Less than 1 Year*	*Maturity 1 to 3 Years*	*Total Fair Value*
Prices actively quoted	$ 15.3	$ 1.0	$ 16.3
Prices based on models and other valuation methods (including prices quoted from external sources)	1.2	0.3	1.5

Regulated Operations Xcel Energy's regulated energy marketing operation uses a combination of energy and gas purchase for resale futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $83.8 million. The fair value of these contracts as of Dec. 31, 2001, was a liability of approximately $24 million.

Nonregulated Operations Xcel Energy's nonregulated operations uses a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $1.0 billion. The fair value of these contracts as of Dec. 31, 2001, was an asset of approximately $242.2 million.

Foreign Currency Xcel Energy and its subsidiaries have two foreign currency swaps to hedge or protect foreign currency denominated cash flows. At Dec. 31, 2001 and 2000, the net notional amount of these contracts was approximately $46.3 million and $8.8 million, respectively. The fair value of these contracts as of Dec. 31, 2001 and 2000 was a liability of approximately $2.4 million and $0.7 million, respectively.

LETTERS OF CREDIT

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one or two years, 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, 2001, there were $221.7 million in letters of credit outstanding, including $169.7 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. DERIVATIVE VALUATION AND FINANCIAL IMPACTS

Business and Operational Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation, retail distribution and energy trading operations. In certain jurisdictions, purchased power expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, we are exposed to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, we recover purchased power expenses and natural gas costs based on fixed price limits or under negotiated sharing mechanisms.

Commodity price risk is managed by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil and derivative financial instruments. Xcel Energy's risk management policy allows us to manage the market price risk within its rate-regulated operations to the extent such exposure exists. Management is limited under the policy to enter into only transactions that reduce market price risk where the rate regulation jurisdiction does not already provide for dollar for dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. This jurisdiction allows us to recover the gains and losses on derivative instruments used to reduce our exposure to market price risk.

Xcel Energy and its subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. Xcel Energy manages this market price risk by entering into firm power sales agreements for approximately 60 to 75 percent of its electric capacity and energy from each generation facility using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed priced electric energy requirements. Xcel Energy's risk management policy allows us to manage the market price risks and provides guidelines for the level of price risk exposure that is acceptable within our operations.

Xcel Energy is exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from our equity method investments that own electric operations. Xcel Energy manages this market price risk through our involvement with the management committee or board of directors of each of these ventures. Our risk management policy does not cover the activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk Xcel Energy and its subsidiaries are exposed to fluctuations in interest rates where we enter into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations is mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy's risk management policy allows us to reduce our interest rate exposure from variable rate debt obligations.

Foreign Currency Risk Xcel Energy and its subsidiaries have certain investments in foreign countries exposing us to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project as well as the risk relative to the earnings and cash flows generated from such operations. Xcel Energy manages its exposure to changes in foreign currency by entering into derivative instruments as determined by management. Our risk management policy provides for this risk management activity.

Trading Risk Xcel Energy and its subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States. and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Xcel Energy's risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by our risk management committee made up of management personnel not involved in the trading operations.

Accounting Change On Jan. 1, 2001, Xcel Energy adopted SFAS No. 133. This statement requires that all derivative instruments as defined by SFAS No. 133 be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument's fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument's gains and losses to offset related results of the hedged item in the income statement, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting.

A fair value hedge requires that the effective portion of the change in the fair value of a derivative instrument be offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the offsetting gain or loss on the hedged item to be reported in an earlier period to offset the gain or loss on the derivative instrument. A cash flow hedge requires that the effective portion of the change in the fair value of a derivative instrument be recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized currently in earnings.

Xcel Energy formally documents its hedge relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. Derivatives are recorded in the balance sheet at fair value. Xcel Energy also formally assesses, both at inception and at least quarterly thereafter, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

The adoption of SFAS No. 133 on Jan. 1, 2001, resulted in an earnings impact of less than $1 million, which is not being reported separately as a cumulative effect of accounting change due to immateriality. In addition, upon adoption of SFAS No. 133, Xcel Energy recorded a net transition loss of approximately $28.8 million in Other Comprehensive Income.

The components of SFAS No. 133 impacts on Xcel Energy's Other Comprehensive Income, included in stockholders' equity, are detailed in the following table:

(Millions of dollars)	
Net unrealized transition loss at adoption, Jan. 1, 2001	$(28.8)
After-tax net unrealized gains related to derivatives accounted for as hedges	43.6
After-tax net realized losses on derivative transactions reclassified into earnings	19.4
Accumulated other comprehensive income related to SFAS No. 133	$ 34.2

The components of the gain for SFAS No. 133 impacts on Xcel Energy's income statement for the year ended Dec. 31, 2001, are detailed in the following table. The amounts below exclude our gains and losses from trading activities.

(Millions of dollars, except per share data)	
Increase (decrease) in income:	
Nonregulated and other revenues	$ (8.1)
Equity earnings from investment in affiliates	4.6
Electric fuel and purchased power – utility	0.1
Cost of goods sold – nonregulated and other	17.5
Other income (deductions)	0.2
Total increase before minority interest and income tax	$14.3
Net-of-tax increase in net income	$ 9.8
Increase in EPS (diluted)	$0.03

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as separate line items noted as Derivative Instruments Valuation for assets and liabilities as well as current and noncurrent.

NORMAL PURCHASES OR NORMAL SALES

Xcel Energy and its subsidiaries enter into fixed price contracts for the purchase and sale of various commodities for use in our business operations. SFAS No. 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented as normal and exempted from the accounting and reporting requirements of SFAS No. 133.

Xcel Energy evaluates all of its contracts within the regulated and nonregulated operations when such contracts are entered into to determine if they are derivatives and if so, if they qualify and meet the normal designation requirements under SFAS No. 133. None of the contracts entered into within the trading operations are considered normal.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

CASH FLOW HEDGES

Xcel Energy and its subsidiaries enter into derivative instruments to manage our exposure to changes in commodity prices. These derivative instruments take the form of fixed price, floating price or index sales or purchases and options, such as puts, calls and swaps. These derivative instruments are designated as cash flow hedges for accounting purposes and the changes in the fair value of these instruments are recorded as a component of Other Comprehensive Income. At Dec. 31, 2001, Xcel Energy had various commodity related contracts extending through 2018. Earnings on these cash flow hedges are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the usage of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings during 2002 net gains from Other Comprehensive Income of approximately $18.0 million.

Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively fix the interest payments on certain floating rate debt obligations. These derivative instruments are designated as cash flow hedges for accounting purposes and the change in the fair value of these instruments is recorded as a component of Other Comprehensive Income. Xcel Energy expects to reclassify into earnings during 2002 net losses from Other Comprehensive Income of approximately $5.6 million.

Xcel Energy records hedge effectiveness based on the nature of the item being hedged. Hedging transactions for the sales of electric energy are recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs and hedging transactions for interest rate swaps are recorded as a component of interest expense.

The net gain (loss) recognized in earnings for derivative instruments that have been designated and qualify as cash flow hedging instruments are detailed in the following table.

(Millions of dollars) *Year ended Dec. 31, 2001*	*Hedge Ineffectiveness*	*Derivatives Excluded from Assessment of Hedge Effectiveness*	*Firm Commitments No Longer Qualifying as Cash Flow Hedges*
Energy and energy-related commodities	$ 27.9	$ –	$ –
Interest rates	–	–	–

FAIR VALUE HEDGES AND HEDGES OF FOREIGN CURRENCY EXPOSURE OF A NET INVESTMENT IN FOREIGN OPERATIONS

To preserve the U.S. dollar value of projected foreign currency cash flows, Xcel Energy, through NRG, may hedge, or protect those cash flows if appropriate foreign hedging instruments are available. Xcel Energy expects to reclassify into earnings during 2002 net losses from Other Comprehensive Income of approximately $2.2 million.

DERIVATIVES NOT QUALIFYING FOR HEDGE ACCOUNTING

Xcel Energy and its subsidiaries have various trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Income. All financial derivative instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Income.

In order to preserve the U.S. dollar value of projected foreign currency cash flows from European trading operations, we enter into various foreign currency exchange contracts that are not designated as accounting hedges but are considered economic hedges. Accordingly, the changes in fair value of these derivatives are reported in Other Nonoperating Income in the Consolidated Statements of Income.

15. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

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, 2001, NSP-Minnesota had loaded 14 of the containers. 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.

Other commitments established by the Legislature included 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 Resources under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2001, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately $2.8 billion in 2002, $2.6 billion in 2003 and $2.7 billion in 2004.

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 $1.6 billion in 2002 for NRG investments and asset acquisitions. NRG's future capital requirements may vary significantly. For 2002, NRG's capital requirements reflect expected acquisitions of existing generation facilities, including the generating assets of FirstEnergy Corp. and the Conectiv fossil assets. See further discussion in Note 19 to the Financial Statements.

Leases Our subsidiaries lease a variety of equipment and facilities used in the normal course of business. Some of these leases qualify as capital leases and are accounted for accordingly. The capital leases expire between 2002 and 2025. The net book value of property under capital leases was approximately $605 million and $55 million at Dec. 31, 2001 and 2000, 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.

The remainder of the leases, primarily leases of coal-hauling railcars, trucks, cars and power-operated equipment are accounted for as operating leases. Rental expense under operating lease obligations was approximately $58 million, $56 million and $57 million for 2001, 2000 and 1999, respectively.

Future commitments under operating and capital leases are:

(Millions of dollars)	*Operating Leases*	*Capital Leases*
2002	$ 54	$ 77
2003	50	75
2004	50	73
2005	48	71
2006	45	69
Thereafter		1,073
Total minimum obligation		$ 1,438
Interest		(834)
Present value of minimum obligation		$ 604

Technology Agreement We have a contract that extends through 2011 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at our option, although there are financial penalties for early termination. In 2001, we paid IBM $130 million under the contract. The contract also commits us to pay a minimum amount each year from 2002 through 2011.

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 2002 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.8 billion of coal, $122.3 million of nuclear fuel and $1.3 billion 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.

Purchased Power Agreements The utility and nonregulated 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, SPS and certain nonregulated subsidiaries have various pay-for-performance contracts with expiration dates through the year 2050. 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.

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 2001 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, 2001, the estimated future payments for capacity that the utility and nonregulated subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Thousands of dollars)	*Total*
2002	$ 507,095
2003	513,979
2004	590,109
2005	658,976
2006 and thereafter	4,135,048
Total	$ 6,405,207

ENVIRONMENTAL CONTINGENCIES

We are subject to regulations covering air and water quality, land use, 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 cost of building and operating our facilities. This includes NRG, which is subject to regional, federal and international environmental regulation.

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, 2001, 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 environmental remediation 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 when 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 PRPs and the identification of new environmental cleanup sites.

We revise our estimates as facts become known, but at Dec. 31, 2001, our liability for the cost of remediating sites for which an estimate was possible was $51 million, including $13 million in current liabilities. Some of the cost of remediation may be recovered from:

- insurance coverage;
- other parties that have contributed to the contamination; and
- 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.

Approximately $19 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 16 to the Financial Statements for further discussion of nuclear obligations.

Ashland MGP Site 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 Chequemegon 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 Enviornmental Protection Agency (EPA) and WDNR have not yet selected the method of remediation to use at the site. 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 determine 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, using information available to date and 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. In 2002, NSP-Wisconsin will install monitor wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the free-product recovery system is operational.

On Dec. 1, 2000, in response to a citizen petition, the EPA proposed the Ashland site for inclusion on the National Priorities List (NPL) of hazardous sites requiring cleanup. NSP-Wisconsin submitted comments in the Administrative Record concerning the proposed listing on Jan. 30, 2001. It is anticipated that the site will be listed on the NPL sometime in 2002.

NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site.

Other MGP Sites NSP-Minnesota has investigated and remediated MGP sites in Minnesota and North Dakota. The MPUC allowed NSP-Minnesota to defer, rather than immediately expense, certain remediation costs of four active remediation sites in 1994. This deferral accounting treatment may be used to accumulate costs that regulators might allow us to recover from our customers. The costs are deferred as a regulatory asset until recovery is approved, and then the regulatory asset is expensed over the same period as the regulators have allowed us to collect the related revenue from our customers. In September 1998, the MPUC allowed the recovery of a portion of these MGP site remediation costs in natural gas rates. Accordingly, NSP-Minnesota has been amortizing the related deferred remediation costs to expense. In 2001, the North Dakota Public Service Commission allowed the recovery of part of the cost of remediating another former MGP site in Grand Forks, N.D. The recovered cost of remediating that site, $2.9 million, was accumulated in a regulatory asset that is now being expensed evenly over eight years. NSP-Minnesota may request recovery of costs to remediate other sites following the completion of preliminary investigations.

Asbestos Removal 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.

Leyden Gas Storage Facility In the fall of 2001, PSCo took its Leyden natural gas storage facility out of commercial storage operation and began final withdrawal of gas as part of the process to permanently close the facility. PSCo is closing the Leyden facility because it is no longer compatible with surrounding land use, which has experienced considerable residential and commercial development in recent years. Through Dec. 31, 2001, $4 million of costs have been incurred. PSCo has deferred expensing these closing costs because it believes that it will be able to recover them from its ratepayers. We will request recovery of the closing costs as part of the rate case to be filed in 2002. Any costs that are not recoverable from customers will be expensed.

Plant Emissions On Dec. 10, 2001, the Minnesota Pollution Control Agency issued a notice of violation to NSP-Minnesota alleging air-quality violations related to the replacement of a coal conveyor and violations of an opacity limitation at the A.S. King generating plant. NSP-Minnesota has responded to the notice of violation and is working to resolve its allegations.

NRG estimates capital expenditures over the next five years related to resolving environmental concerns at the Indian River Generating Station, which are centered around possible closure of the existing landfill and construction of a new cell to replace it, possible addition of a cooling tower, and the addition of controls to reduce nitrogen oxide (NO_X) emissions. Currently, cost estimates for addressing the first two items vary widely pending the results of negotiations with the Delaware Natural Resources and Environment Commission (DNREC). If ash sales are poor, it is estimated that NRG could spend up to $11 million over the five-year timeframe to close/construct sections of the landfill; if sales are robust, expenditures related to closure/construction are expected to be minimal. In the unlikely event NRG is unable to reach agreement with DNREC on extension of a variance, NRG estimates a $40-million cooling tower could be required; if negotiations are successful, a cooling tower can be avoided.

NRG also estimates $39 million of capital expenditures at its Encina Generating Station to install emission-control equipment required by California regulation passed in late 2001. Installation is expected to be completed in the spring of 2003.

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 and on sulfur dioxide (SO_2) commencing in December 2003, with further reductions required by December 2005, and on carbon dioxide (CO_2) by December 2005. In addition to output-based limits (a standard that limits emissions to a certain rate per net megawatt-hour), the proposed regulations also would limit, by December 2003, the total emissions of NO_X and SO_2 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 CO_2 emission rate identified in the proposed regulations cannot be met by the Somerset facility. NRG has submitted an emission control plan, with respect to the NO_X and SO_2 requirements, and is conducting ongoing discussions with the MDEP regarding finalization of the plan.

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 $10 million for property damage insurance if losses exceed accumulated reserve funds.

LEGAL CONTINGENCIES

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.

St. Cloud Gas Explosion 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 24 lawsuits relating to the explosion. NSP-Minnesota, Seren's parent company at the time, is a defendant in 21 of the lawsuits. In addition to compensatory damages, plaintiffs are seeking punitive damages against CCI and Seren. 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 causes 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.

California Litigation 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, Calif. in November 2000. NRG has also been named in another suit filed in January 2001 in San Diego County and brought by three California water districts, as consumers of electricity, and in two suits filed in San Francisco County, one brought by the San Francisco City Attorney on behalf of the people of the State of California and one brought by Pier 23 Restaurant as a class action. Certain NRG affiliates in NRG's West Coast power partnership with Dynegy (Cabrillo I and II, Long Beach Generation and El Segundo Power) have been named as defendants in a state court action in Los Angeles County.

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 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. These six civil actions brought against NRG and other power generators and power traders in California have been consolidated and assigned to the presiding judge of the San Diego County Superior Court, and a pretrial conference has been scheduled for March 2002. While it is too soon to speculate on the outcome of these cases, it could have a material adverse effect on NRG's results of operations and financial condition if they were ultimately resolved adversely to the defendants.

Other Litigation In January 2002 the New York Attorney General and the New York Department of Environmental Control filed suit in the western district of New York against NRG and Niagara Mohawk Power Corporation, the prior owner of the Huntley and Dunkirk facilities in New York. The lawsuit relates to physical changes made at those facilities prior to NRG's assumption of ownership. The complaint alleges that these changes represent major modifications undertaken without the required permits having been obtained. Although NRG has a right to indemnification by the previous owner for fines, penalties, assessments and related losses resulting from the previous owner's failure to comply with environmental laws and regulations, NRG could be enjoined from operating the facilities if the facilities are found not to comply with applicable permit requirements.

In July 2001, Niagara Mohawk Power Corporation filed a declaratory judgment action in the Supreme Court for the State of New York, County of Onondaga, against NRG and its wholly owned subsidiaries Huntley Power LLC and Dunkirk Power LLC. Niagara

Mohawk Power Corporation requests a declaration by the Court that, pursuant to the terms of the Asset Sales Agreement (the ASA) under which NRG purchased the Huntley and Dunkirk generating facilities from Niagara Mohawk, defendants have assumed liability for any costs for the installation of emissions controls or other modifications to or related to the Huntley or Dunkirk plants imposed as a result of violations or alleged violations of environmental law. Niagara Mohawk Power Corporation also requests a declaration by the Court that, pursuant to the ASA, defendants have assumed all liabilities, including liabilities for natural resource damages, arising from emissions or releases of pollutants from the Huntley and Dunkirk plants, without regard to whether such emissions or releases occurred before, on or after the closing date for the purchase of the Huntley and Dunkirk plants. NRG has counterclaimed against Niagara Mohawk Power Corporation, and the parties have exchanged discovery requests.

OTHER CONTINGENCIES

California Power Market NRG's California generation assets include a 57.67-percent interest in Crockett Cogeneration (Crockett), a 39.5-percent interest in the Mt. Poso facility and a 50-percent interest in the West Coast Power partnership with Dynegy.

In March 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Bankruptcy Code, and in April 2001, Pacific Gas & Electric Co. (PG&E) also filed for bankruptcy under Chapter 11. PG&E's filing delayed collection of receivables owed to the Crockett facility. In September 2001, PG&E filed a proposed plan of reorganization. Under the terms of the proposed plan, which is subject to challenge by interested parties, unsecured creditors such as NRG's California affiliates would receive 60 percent of the amounts owed upon approval of the plan. The remaining 40 percent would be paid in negotiable debt with terms from 10 to 30 years. The California PX's ability to repay its debt is dependent on the extent to which it receives payments from PG&E and Southern California Edison Co. On Dec. 21, 2001, the California bankruptcy court affirmed the Mt. Poso and Crockett power purchase agreements with PG &E and, in respect of the Crockett power purchase agreement, approved a 12-month repayment schedule of all past due amounts totaling, $49.6 million, plus interest. The first payment of $6.2 million, including accrued interest, was received on Dec. 31, 2001.

NRG's share of the net amounts owed to West Coast Power by the California Independent System Operator (ISO) and PX totaled approximately $85.1 million as of Dec. 31, 2001, compared with $101.8 million at Dec. 31, 2000. These amounts reflect NRG's share of total amounts owed to West Coast Power less amounts that are currently treated as disputed revenues and are not recorded as accounts receivable in the financial statements of West Coast Power, and reserves taken against accounts receivable that have been recorded in the financial statements. The decrease is primarily attributed to cash collections from the California ISO during the fourth quarter of 2001.

The FERC has set for investigation the justness and reasonableness of the rates of wholesale sellers into the California ISO and PX markets and is making such rates subject to refund effective November 2001. The effect of the FERC's action is to make certain transactions of PSCo and NRG in California subject to refund. Xcel Energy believes that PSCo's refund exposure is immaterial. NRG has estimated potential refunds in the calculation of the reserves taken against its related accounts receivable.

Enron Xcel Energy, through its subsidiaries (excluding NRG as discussed later), has entered into agreements with Enron and its subsidiaries. However, pursuant to netting/set-off rights provisions of the industry standard agreements that Xcel Energy and Enron have utilized, Xcel Energy generally has a net liability to Enron. Therefore, we will owe Enron termination payments under these agreements for such services. The most significant of these agreements is between Enron and e prime. e prime will owe Enron a termination payment of approximately $12 million, representing the net of a $69-million receivable and an $81-million payable. As a result of the netting/set-off provisions, no provision for loss has been recorded in connection with these transactions agreements. Xcel Energy does not expect a material impact to the results of its operations as a direct result of the bankruptcy filing of Enron.

During 2001, NRG's power marketing operation recorded a net after-tax expense of $6.7 million related to Enron's bankruptcy. This amount includes a $14.2-million, after-tax charge to establish bad debt reserves, which was partially offset by a $7.5-million, after-tax gain on a credit swap agreement entered into as part of NRG's credit risk management program. NRG has fully provided for its exposure to Enron; however, as with any receivable, NRG will pursue collection of all amounts outstanding through the ordinary course of business.

In addition, an Enron subsidiary, NEPCO, is serving as the construction contractor for two of NRG's greenfield development projects, the Kendall and Nelson projects currently under construction in Illinois. Enron guaranteed NEPCO's obligations under the construction contracts. To date, the actual construction and engineering work on both projects has continued without disruption, and NRG expects the projects to achieve commercial operations on schedule. NRG believes overall construction costs will increase by no more than $50 million, which represents less than five percent of the expected construction costs.

Tax Matters The IRS had issued a Notice of Proposed Adjustment proposing to disallow interest expense deductions taken in tax years 1993 through 1997 related to corporate-owned life insurance (COLI) policy loans of PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo. A request for technical advice from the IRS National Office with respect to the proposed adjustment had been pending. Late in 2001, Xcel Energy received a technical advice memorandum from the IRS National Office, which communicated a position adverse to PSRI. Consequently, we expect the IRS examination division to begin the process of disallowing the interest expense deductions for the tax years 1993 through 1997.

After consultation with tax counsel, it is Xcel Energy's position that the IRS determination is not supported by the tax law. Based upon this assessment, management continues to believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the tax law. Therefore, Xcel Energy intends to challenge the IRS determination, which could require several years to reach final resolution. Although the ultimate resolution of this matter is uncertain, management continues to believe 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.

The total disallowance of interest expense deductions for the period of 1993 through 1997, as proposed by the IRS, is approximately $175 million. Additional interest expense deductions for the period 1998 through 2001 are estimated to total approximately $240 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2001, would reduce earnings by an estimated $197 million (after tax), or 57 cents per Xcel Energy share.

Seren At Dec. 31, 2001, Xcel Energy's investment in Seren was approximately $232 million. Seren had capitalized $190 million for plant in service and had incurred another $60 million for construction work in progress for these systems. The construction of its broadband communications network in Minnesota and California has resulted in consistent losses. Management currently intends to hold and operate Seren, and believes that no asset impairment exists. Xcel Energy is evaluating the strategic fit in its business portfolio.

Loy Yang NRG owns a 25.37 percent interest in Loy Yang Power, which owns and operates the 2,000-megawatt Loy Yang A brown coal-fired thermal power station and the adjacent Loy Yang coal mine located in Victoria, Australia. Energy prices in the Victoria region of the National Electricity Market of Australia, into which the Loy Yang facility sells its power have been significantly lower than NRG expected when it acquired its interest in the facility. Prices improved during 2001, resulting in a 14-percent revenue increase. Despite this improvement, a significant unplanned outage, beginning in late December 2001 and expected to last until April 2002, will result in a reduction in 2002 revenues and cash flows. Such reduction may cause the Loy Yang project company to fail its required coverage ratios under its loan agreements during the next 12 months, which would constitute an event of default. In the case of default, the project company's lenders would be allowed to accelerate the project company's indebtedness. The ultimate financial impact of the outage is subject to continuing investigation and is also subject to several events, including the receipt and timing of insurance proceeds, the cost and timing of repairs to the damaged unit and electricity market conditions. Project management is actively pursuing each of these options to mitigate the impact of the outage. However, in the event all factors are unfavorable, NRG may be required to either infuse more cash or write off all or a portion of its $250-million investment in this project as a result of such acceleration. In its current circumstances, Loy Yang Power is prohibited by its loan agreements from making equity distributions to the project owners.

Xcel Energy International At Dec. 31, 2001, Xcel Energy's investment in Argentina through Xcel Energy International was $102 million. Given the political and economic climate in Argentina, Xcel Energy continues to closely monitor the investment for asset impairment. Due to the declining value of the Argentine peso, a currency translation adjustment was recorded in the amount of $38 million as an adjustment to Other Comprehensive Income. Currently, management intends to hold and operate the investment and believes that no asset impairment exists.

16. 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-Minnesota'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 $11 million in 2001, $12 million in 2000 and $12 million in 1999. In total, NSP-Minnesota had paid approximately $296 million to the DOE through Dec. 31, 2001. 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 for spent fuel 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 all of the 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 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2001 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 $25 million at Dec. 31, 2001, 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 Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy's financial statements.

In June 2001, the FASB approved the issuance of SFAS No. 143 – "Accounting for Asset Retirement Obligations." This statement will require us to record our future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset's useful life, the recorded liability differs from the actual obligations paid, a gain or loss will be recognized at that time.

SFAS No. 143 will also affect our accrued plant removal costs for other generation, transmission and distribution facilities for our utility subsidiaries. We expect that these costs, which have yet to be estimated, will be reclassified from Accumulated Depreciation to Regulatory Liabilities based on the recoverability of these costs in rates. We plan to adopt SFAS No. 143, as required, on Jan. 1, 2003.

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 4.35 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. Unrealized gains on nuclear decommissioning investments are deferred as Regulatory Liabilities based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

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 spent-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, 2001, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in one to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

At Dec. 31, 2001, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $623 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation at Dec. 31, 2001:

(Thousands of dollars)	*2001*
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	$ 958,266
Effect of escalating costs to 2001 dollars (at 4.35 percent per year)	85,183
Estimated decommissioning cost obligation in current dollars	1,043,449
Effect of escalating costs to payment date (at 4.35 percent per year)	850,825
Estimated future decommissioning costs (undiscounted)	1,894,274
Effect of discounting obligation (using risk-free interest rate)	(1,016,206)
Discounted decommissioning cost obligation	878,068
Assets held in external decommissioning trust	596,113
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 281,955

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	*2001*	*2000*	*1999*
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$ 51,433	$ 51,433	$ 33,178
Internally funded (including interest costs)	(17,396)	(16,111)	1,595
Interest cost on externally funded decommissioning obligation	4,535	5,151	4,191
Earnings from external trust funds	(4,535)	(5,151)	(4,191)
Net decommissioning accruals recorded	$ 34,037	$ 35,322	$ 34,773

Decommissioning and interest accruals are included with Accumulated Depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the income statement.

Negative accruals for internally funded portions in 2000 and 2001 reflect the impacts of the 2000 decommissioning study, which has approved an assumption of 100-percent external funding of future costs. Previous studies assumed a portion was funded internally; beginning in 2000, accruals are reversing the previously accrued internal portion and increasing the external portion prospectively.

17. REGULATORY ASSETS AND LIABILITIES

Our regulated businesses prepare their financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Financial Statements. Under SFAS No. 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. Any portion of our business that is not regulated cannot use SFAS No. 71 accounting. The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

(Thousands of dollars)	*Note Ref.*	*Remaining Amortization Period*	*2001*	*2000*
AFDC recorded in plant *(a)*		Plant Lives	$ 149,591	$159,406
Conservation programs *(a) (d)*		Up to 5 Years	65,825	52,444
Losses on reacquired debt	1	Term of Related Debt	95,394	85,688
Environmental costs	15 and 16	To be determined	20,169	19,372
Unrecovered gas costs *(b)*	1	1–2 Years	11,316	24,719
Deferred income tax adjustments	1	Mainly Plant Lives	17,799	–
Nuclear decommissioning costs *(e)*		Up to 8 Years	68,484	82,490
Employees' postretirement benefits other than pension	10	11 Years	42,942	46,680
Employees' postemployment benefits	2	2–3 Years	119	23,223
Renewable resource costs		To be determined	17,500	10,500
State commission accounting adjustments *(a)*		Plant Lives	7,578	7,614
Other		Various	5,725	12,125
Total regulatory assets			$ 502,442	$524,261
Investment tax credit deferrals			$ 117,257	$119,060
Unrealized gains from decommissioning investments	16		149,041	171,736
Pension costs-regulatory differences	10		215,687	139,178
Conservation programs *(c)*			–	40,679
Deferred income tax adjustments			–	12,416
Fuel costs, refunds and other			1,957	11,497
Total regulatory liabilities			$ 483,942	$494,566

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(b) Excludes current portion with expected rate recovery within 12 months of $22 million and $13 million for 2001 and 2000, respectively.
(c) Represents estimated refund for 1998 incentives; ultimately reversed in 2001.
(d) 2001 amount includes accrued conservation incentives expected to be approved for 2001 and 2000. Due to regulatory uncertainty, such incentives were not accrued in 2000.
(e) These costs do not relate to NSP-Minnesota's nuclear plants. They relate to DOE assessments (as discussed previously) and amortized costs for PSCo's Fort St. Vrain nuclear plant decommisioning.

18. SEGMENT AND RELATED INFORMATION

Xcel Energy has the following reportable segments: Electric Utility, Gas Utility and two of its nonregulated energy businesses, NRG and e prime. During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power. As a result of this sales agreement, Xcel International (Yorkshire Power was Xcel International's most significant holding) is no longer a reportable segment. Prior periods have been restated for comparability.

– 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, 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.
– e prime trades and markets natural gas throughout the United States.

Revenues from operating segments not included previously 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 to the Financial Statements. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

BUSINESS SEGMENTS

(Thousands of dollars)	*Electric Utility*	*Gas Utility*	*NRG*	*e prime*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
							2001
Operating revenues from external customers *(a)*	$7,731,640	$2,051,199	$2,803,073	$1,848,969	$373,823	$ –	$14,808,704
Intersegment revenues	978	4,501	1,859	88,475	89,636	(183,019)	2,430
Equity in earnings (losses) of unconsolidated affiliates	–	–	208,613	1,376	7,081	–	217,070
Total revenues	$7,732,618	$2,055,700	$3,013,545	$1,938,820	$470,540	$(183,019)	$15,028,204
Depreciation and amortization	$ 617,320	$ 92,989	$ 212,493	$ 247	$ 26,151	$ –	$ 949,200
Financing costs, mainly interest expense	265,285	49,108	450,729	277	107,855	(52,055)	821,199
Income tax expense (credit)	351,181	41,077	33,477	5,150	(94,162)	–	336,723
Segment income (loss) before extraordinary items	$ 535,182	$ 81,562	$ 265,204	$ 8,547	$ (65,426)	$ (40,390)	$ 784,679
Extraordinary items, net of tax	11,821	–	–	–	(1,534)	–	10,287
Segment net income (loss)	$ 547,003	$ 81,562	$ 265,204	$ 8,547	$ (66,960)	$ (40,390)	$ 794,966
							2000
Operating revenues from external customers *(a)*	$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	1,203	39,425	–	182,714
Total revenues	$6,493,373	$1,472,239	$2,159,099	$1,324,637	$280,410	$(137,962)	$11,591,796
Depreciation and amortization	$ 574,018	$ 85,353	$ 123,404	$ 569	$ 9,051	$ –	$ 792,395
Financing costs, mainly interest exp.	333,512	60,755	295,917	200	65,501	(59,780)	696,105
Income tax expense (credit)	261,942	36,962	92,474	(3,995)	(82,518)	–	304,865
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$ (6,158)	$ (13,925)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)	–	–	–	–	–	(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (6,158)	$ (13,925)	$ (15,609)	$ 526,828

BUSINESS SEGMENTS CONTINUED

(Thousands of dollars)	*Electric Utility*	*Gas Utility*	*NRG*	*e prime*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
Operating revenues							**1999**
from external customers *(a)*	$5,454,958	$1,141,294	$ 427,567	$ 564,045	$136,570	$ –	$ 7,724,434
Intersegment revenues	1,303	11,785	963	2,102	119,546	(134,731)	968
Equity in earnings (losses)							
of unconsolidated affiliates	–	–	68,947	1,467	41,710	–	112,124
Total revenues	$5,456,261	$1,153,079	$ 497,477	$ 567,614	$297,826	$(134,731)	$ 7,837,526
Depreciation and amortization	$ 546,794	$ 82,206	$ 37,026	$ 3,762	$ 14,187	$ –	$ 683,975
Financing costs, mainly interest exp.	300,108	53,217	92,570	226	25,976	(19,020)	453,077
Income tax expense (credit)	272,129	24,081	(26,416)	(2,984)	(73,002)	(14,135)	179,673
Segment net income (loss)	$ 431,510	$ 49,175	$ 57,195	$ (4,765)	$ 50,939	$ (13,121)	$ 570,933

(a) All operating revenues are from external customers located in the United States, except $764 million and $290 million of NRG operating revenues in 2001 and 2000, respectively, 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 $54.1 million in 2001, $19.2 million in 2000 and $38.6 million in 1999 from nonregulated projects located outside of the United States. NRG's equity investments in projects outside of the United States were $519 million in 2001, $566 million in 2000 and $606 million in 1999. All Other equity in earnings of unconsolidated affiliates includes $1 million in 2001, $35.3 million in 2000 and $44.9 million in 1999 from outside of the United States, primarily related to Yorkshire Power. All Other equity investments and projects outside of the United States were $36.9 million in 2001, $383 million in 2000 and $367 million in 1999. In addition, NRG's wholly owned foreign assets ($2.8 billion in 2001 and $796 million in 2000) contributed earnings of $49.2 million in 2001, $30.1 million in 2000 and $0 in 1999.

19. SUBSEQUENT EVENT – NRG TENDER OFFER (UNAUDITED)

Numerous factors have recently led to significant erosion in the market valuations within the independent power production sector, and resulted in a fundamental shift in market perception that has increased the cost of capital for these companies in 2002. As discussed in Management's Discussion and Analysis, since December 2001, NRG has experienced tightening credit standards and has been notified by certain credit rating agencies that NRG's corporate securities have been placed under review for possible downgrade. In response to these developments, Xcel Energy's board of directors and management have been reviewing their options with respect to NRG's funding and structure.

On Feb. 14, 2002, Xcel Energy's board of directors approved plans to commence an exchange offer by which Xcel Energy would acquire all of the outstanding publicly held shares of NRG, representing an approximately 26-percent minority ownership. In the offer, NRG shareholders would receive 0.4846 shares of Xcel Energy common stock in a tax-free exchange for each outstanding share of NRG common stock. Based on the Feb. 14, 2002 closing prices of Xcel Energy and NRG common stock, the exchange ratio represents a 15-percent premium. In addition, following completion of the transaction, shareholders would be entitled to Xcel Energy's current annual dividend of $1.50 per share.

NRG's board of directors must review the proposed transaction, consider whether independent financial and legal advisors are necessary and communicate with NRG's minority shareholders. In order to meet the conditions of the offer, enough shares will need to be tendered so that Xcel Energy's ownership level of NRG reaches 90 percent. Based on the number of shares of NRG common stock outstanding on Feb. 14, 2002, this would require the tender of at least 60 percent of the shares of NRG common stock. As this report went to press, it was not known what NRG's board of directors would recommend, or how many minority shares of NRG would be tendered. Xcel Energy anticipates that the exchange offer will proceed and be completed promptly.

In addition to the exchange offer, on Feb. 15, 2002, Xcel Energy also announced other plans for NRG in 2002:

- Infusing $600 million of equity into NRG, including an estimated $400 million from Xcel Energy common stock issuances under existing shelf registrations;
- Placing approximately $1.9 billion of existing, NRG generating assets onto the market for possible sale;
- Canceling approximately $700 million of planned NRG projects, and deferring about $900 million of other NRG projects;
- Selling unassigned turbines currently under order by NRG;
- Reducing NRG's business development and administrative and general expenses by about $45 million per year in comparison to current levels; and
- Consolidating NRG's trading and marketing organizations, and integrating NRG's power plant management into the Xcel Energy system.

On Feb. 15, 2002, eight separate civil actions were filed in the Court of Chancery of the State of Delaware by owners of NRG common stock against Xcel Energy, NRG and NRG's directors. The complaints contain a number of allegations, but the basic claim is that Xcel Energy proposes to acquire the remaining ownership of NRG for inadequate consideration and without full and complete disclosure of all material information, in breach of defendants' fiduciary duties. The complaints request the court to enjoin the proposed transaction and, in the event the exchange offer is consummated, to award damages to defendants.

20. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
(Thousands of dollars except per share amounts)	*March 31, 2001*	*June 30, 2001 (a)*	*Sept. 30, 2001*	*Dec. 31, 2001 (a)*
Revenue	$4,230,568	$3,698,557	$3,763,474	$3,335,605
Operating income *(c)*	492,306	433,765	658,379	358,498
Income before extraordinary items	209,310	167,857	272,903	134,609
Extraordinary items	–	–	–	10,287
Net income	209,310	167,857	272,903	144,896
Earnings available for common shareholders	208,250	166,797	271,843	143,835
Earnings per share before extraordinary items:				
Basic	$ 0.61	$ 0.49	$ 0.79	$ 0.39
Diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.38
Earnings per share extraordinary items – basic & diluted	$ 0.00	$ 0.00	$ 0.00	$ 0.03
Earnings per share after extraordinary items:				
Basic	$ 0.61	$ 0.49	$ 0.79	$ 0.42
Diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.41

	Quarter Ended			
(Thousands of dollars except per share amounts)	*March 31, 2000*	*June 30, 2000*	*Sept. 30, 2000 (b)*	*Dec. 31, 2000 (b)*
Revenue	$2,335,709	$2,461,752	$3,100,398	$3,693,937
Operating income *(c)*	361,749	429,728	402,595	374,536
Income before extraordinary items	153,331	156,741	97,916	137,800
Extraordinary items	–	(13,658)	(5,302)	–
Net income	153,331	143,083	92,614	137,800
Earnings available for common shareholders	152,271	142,022	91,554	136,740
Earnings per share before extraordinary items:				
Basic	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Diluted	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Earnings per share extraordinary items – basic & diluted	$ 0.00	$(0.04)	$(0.02)	$ 0.00
Earnings per share after extraordinary items:				
Basic	$ 0.45	$ 0.42	$ 0.20	$ 0.40
Diluted	$ 0.45	$ 0.42	$ 0.27	$ 0.40

(a) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Notes 2 and 17 to the Financial Statements. Second quarter results were increased by $41 million, or 7 cents per share, for conservation incentive adjustments, and decreased by $23 million, or 4 cents per share, for a special charge related to postemployment benefits. Fourth quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.

(b) 2000 results include special charges related to merger costs and strategic alignment, as discussed in Note 2 to the Financial Statements. Third quarter results were reduced by approximately $201 million, or 43 cents per share. Fourth quarter results were reduced by approximately $40 million, or 9 cents per share.

(c) Certain items in the 2000 and 2001 quarterly income statements have been reclassified to conform to the 2001 annual presentation. These reclassifications, primarily related to items formerly presented as nonoperating revenues and expenses, had no effect on net income or earnings per share.

SHAREHOLDER INFORMATION

HEADQUARTERS
800 Nicollet Mall, Minneapolis, Minn. 55402

INTERNET ADDRESS
www.xcelenergy.com

INVESTORS HOTLINE
1-877-914-9235

SHAREHOLDERS INFORMATION
Contact Wells Fargo Shareowners Services, the Xcel Energy Inc. stock transfer agent, toll free at 1-877-778-6786.

XCEL ENERGY DIRECT PURCHASE PLAN
Xcel Energy's Direct Purchase Plan, offered by prospectus, is a convenient way to purchase shares of Xcel Energy's common stock without payment of any brokerage commission or service charge. Contact Wells Fargo Shareowners Services, the plan administrator, at 1-877-778-6786 for a prospectus and authorization form.

REPORTS AVAILABLE ONLINE
Financial reports, including filings with the Securities and Exchange Commission, and Xcel Energy's Report to Shareholders are available online at www.xcelenergy.com.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL
Common stock is traded on the New York, Chicago and Pacific exchanges. Ticker symbol: XEL. NYSE lists some of Xcel Energy's preferred stock.

INVESTOR RELATIONS
Internet address: www.xcelenergy.com; or contact Richard Kolkmann, Managing Director, Investor Relations, 612-215-4559 or Paul Johnson, Director, Investor Relations, 612-215-4535.

SCHEDULE OF ANTICIPATED DIVIDEND RECORD DATES AND PAYMENT DATES FOR 2002:

Declaration Dates	*Preferred Stock Record Dates*	*Payment Dates*	*Declaration Dates*	*Common Stock Record Dates*	*Payment Dates*
Dec. 12, 2001	Dec. 31, 2001	Jan. 15, 2002	Dec. 12, 2001	Jan. 2, 2002	Jan. 20, 2002
Feb. 27, 2002	March 29, 2002	April 15, 2002	March 27, 2002	April 8, 2002	April 20, 2002
April 18, 2002	June 28, 2002	July 15, 2002	June 26, 2002	July 8, 2002	July 20, 2002
Aug. 28, 2002	Sept. 30, 2002	Oct. 15, 2002	Aug. 28, 2002	Oct. 2, 2002	Oct. 20, 2002
Dec. 11, 2002	Dec. 31, 2002	Jan. 15, 2003			

FISCAL AGENTS

XCEL ENERGY INC.

Transfer Agent, Registrar, Dividend Distribution, Common and Preferred Stocks
Wells Fargo Bank Minnesota, N.A., 161 North Concord Exchange, South St. Paul, Minn. 55075

Trustee-Bonds
Wells Fargo Bank Minnesota, N.A., Sixth St. and Marquette Ave., Minneapolis, Minn. 55479-0059

Coupon Paying Agents-Bonds
Wells Fargo Bank Minnesota, N.A., Minneapolis

XCEL ENERGY DIRECTORS

Wayne H. Brunetti*
Chairman, President and CEO
Xcel Energy Inc.

C. Coney Burgess [2, 3]
Chairman and President
Burgess-Herring Ranch Company

David A. Christensen [2, 4]
Retired President and CEO
Raven Industries, Inc.

Roger R. Hemminghaus [1, 4]
Chairman Emeritus
Ultramar Diamond Shamrock Corporation

A. Barry Hirschfeld [2, 3]
President
A.B. Hirschfeld Press, Inc.

Douglas W. Leatherdale [2, 3]
Retired Chairman and CEO
The St. Paul Companies, Inc.

Albert F. Moreno [1, 4]
Senior Vice President and General Counsel
Levi Strauss & Co.

Dr. Margaret R. Preska [1, 3]
President Emerita
Minnesota State University – Mankato
Distinguished Service Professor
Minnesota State Universities

A. Patricia Sampson [2, 4]
President and CEO
The Sampson Group, Inc.

Allan L. Schuman [1, 3]
Chairman and CEO
Ecolab, Inc.

Rodney E. Slifer [1, 4]
Partner
Slifer, Smith & Frampton

W. Thomas Stephens [2, 3]
Retired President and CEO
MacMillan Bloedel, Ltd.

Board Committees:
1. *Audit*
2. *Compensation and Nominating*
3. *Finance*
4. *Operations and Nuclear*

**Wayne H. Brunetti is an ex officio member of all committees.*

XCEL ENERGY PRINCIPAL OFFICERS

Paul J. Bonavia
President – Energy Markets

Wayne H. Brunetti
Chairman, President and Chief Executive Officer

Cathy J. Hart
Vice President and Corporate Secretary

Gary R. Johnson
Vice President and General Counsel

Richard C. Kelly
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