XCEL ENERGY | 2007 ANNUAL REPORT

Xcel Energy®

WE ARE THE ENERGY

ANNUAL REPORT
2007

This annual report is printed using soy-based inks on paper that is made from 100 percent post-consumer FSC Certified Fiber.

The use of this paper saved:

- 120 trees;
- 43,875 gallons of water;
- 83 million BTUs of energy; and
- 27,963 pounds of carbon dioxide.

Environmental impact estimates were made using the Environmental Defense calculator and the U.S. EPA's Power Profiler.

Once again, we are delighted to include a DVD in this year's annual report so our shareholders have an opportunity to see and hear Xcel Energy employees in action. *We Are The Energy* illustrates our commitment to improving the environment, delivering reliable energy, helping businesses thrive, caring for our communities and building value for you. We've also included executive profiles of Xcel Energy Chairman, President and CEO Dick Kelly and Vice President and CFO Ben Fowke, who describe the company's commitments, strategies and results.

We hope you enjoy it.

This is a universally formatted DVD that will play on all console DVD players. If you are playing this on a laptop or desktop computer, please make sure that your system has a DVD drive.



On the cover: Xcel Energy employee **Mark Anderson**

# 2007 RESULTS

Xcel Energy employee **Teresa Hrdlicka**

## COMPANY DESCRIPTION

Xcel Energy is a major U.S. electric and natural gas company, with annual revenues of $10 billion. Based in Minneapolis, Minn., Xcel Energy operates in eight states. The company provides a comprehensive portfolio of energy-related products and services to 3.3 million electricity customers and 1.8 million natural gas customers.

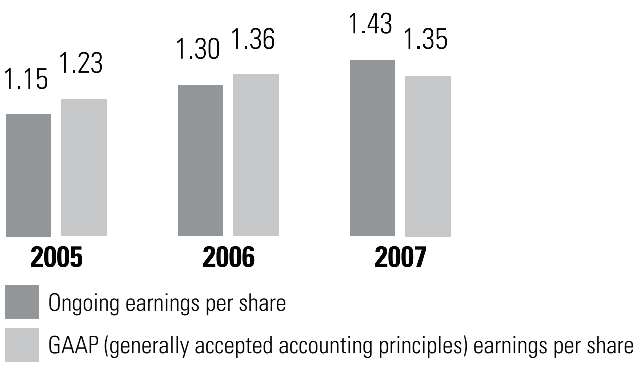
## FINANCIAL HIGHLIGHTS

| | 2007 | 2006 |
|---|---|---|
| Ongoing earnings per share | $ 1.43 | $ 1.30 |
| Total GAAP earnings per share | $ 1.35 | $ 1.36 |
| Dividends annualized | $ 0.92 | $ 0.89 |
| Stock price (close) | $ 22.57 | $ 23.06 |
| Assets (millions) | $ 23,185 | $ 21,958 |
| Book value per common share | $ 14.70 | $ 14.28 |

Some of the sections in this annual report, including the letter to shareholders on page 3, contain forward-looking statements. For a discussion of factors that could affect operating results, please see the management's discussion and analysis listed in the table of contents of the Form 10-K.

## XCEL ENERGY EARNINGS PER SHARE

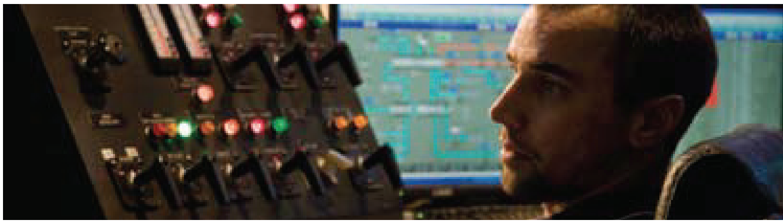
Dollars per share (diluted)



**Dick Kelly,** Chairman, President and CEO

# LETTER TO SHAREHOLDERS

Xcel Energy employee **John Byboth**



**DEAR SHAREHOLDERS:**

With strong financial results, a proven commitment to environmental leadership and a strategy that positions us for long-term success, Xcel Energy had an outstanding year in 2007. We continued to invest in our core electric and natural gas businesses, which enabled us to meet a growing demand for energy, improve the environment and build value for you.

As this report and accompanying DVD illustrate, we are the energy behind:

- The most significant commitment to wind energy in the nation;
- The largest investment in new transmission in decades;
- One of the most ambitious voluntary emission-reduction efforts in the country;
- A major, long-standing, collaborative effort with customers to conserve energy; and
- Promising new technology.

Let's take a closer look at an excellent year.

## STRONG FINANCIAL RESULTS

We exceeded expectations when we delivered ongoing earnings per share of $1.43, compared with $1.30 per share in 2006. As you recall, our revised 2007 ongoing earnings guidance was a range of $1.38 to $1.42 per share. Electric and natural gas rate increases and other cost recovery mechanisms, retail sales growth and favorable temperatures contributed to those results.

Ongoing earnings reflect the fundamental strength of Xcel Energy, but do not include the impact of a settlement we reached with the Internal Revenue Service in 2007 over our company-owned life insurance (COLI) program. When COLI and other discontinued operations are included as part of our GAAP (generally accepted accounting principles) earnings, the result is $1.35 per share, compared with $1.36 per share in 2006.

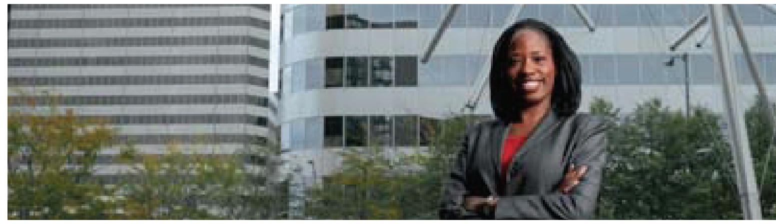
Although COLI made a one-time impact on GAAP earnings, we were pleased to resolve the dispute and consider the settlement one of our 2007 accomplishments. It removed a significant potential liability on favorable terms, enabling us to reduce financial risk.

We're also proud of the progress we've made in strengthening our credit quality. In 2007, Standard & Poor's upgraded the credit ratings of Xcel Energy and its subsidiaries, citing our strengthening business profile and supportive regulation as the basis for the upgrade. Credit quality, a strong balance sheet and conservative financial management enable us to deliver on our financial goals, including growing your dividend rate at 2 percent to 4 percent per year. In 2007, Xcel Energy's board of directors increased your dividend by 3.4 percent.

Strong 2007 results and the momentum we've established this year prompt us to reaffirm our 2008 earnings guidance of $1.45 to $1.55 per share.


Xcel Energy employee **Keith Legatt**

Xcel Energy employee **Helena Haynes-Carter**



## A SUCCESSFUL STRATEGY

As part of meeting our financial goals, we continued to execute our long-term corporate strategy, which is a straightforward plan that starts with listening to customers, who want reliable energy produced in an environmentally responsible way. We make significant investments to meet those customer needs, but before we invest, we work with regulators and legislators to ensure that the regulatory rules are in place to enable us to recover our costs and earn a fair return. In the end, everyone benefits. Customers are satisfied, our impact on the environment is lessened and our shareholders earn a solid return.

In 2007, we made good progress on several significant investments that illustrate our strategy in action. We completed the refurbishment of our Allen S. King coal-fired plant in Minnesota by adding state-of-the-art emission-reduction equipment and rehabilitating existing generating equipment. Minnesota Gov. Tim Pawlenty joined us for a dedication ceremony, calling Xcel Energy one of the most progressive utilities in the nation in terms of environmental responsibility. As part of our larger emission-reduction effort, we also are converting two coal-fired plants in Minnesota to natural gas and are seeking permission to refurbish Sherco, our largest coal-fired plant in the state. Each project adds generating capacity while reducing emissions, so we address reliability along with environmental protection.

In Colorado, work continued on Comanche 3, a 750-megawatt generating unit at our Comanche coal-fired facility near Pueblo. It's a project we started several years ago after reaching a comprehensive settlement with several prominent environmental groups. We will own 500 megawatts of the new unit and are fitting all three units with advanced emission-reduction equipment. As a result, we will more than double the capacity of the entire Comanche facility, while lowering overall sulfur dioxide and nitrogen oxide emissions from the plant. The new unit should be operational in late 2009.

Transmission construction represented another significant investment, with 2007 as a record year. Among other transmission projects, we increased our ability to deliver wind power from the Buffalo Ridge in Minnesota from 425 megawatts of wind energy to 825 megawatts, representing the largest transmission investment in the state in decades. Looking ahead, we are part of consortia in Minnesota and Colorado that are examining regional transmission needs into the future. The effort is further along in Minnesota, where we've joined 10 other utilities seeking to build about 700 miles of new transmission line in the first phase of transmission system expansion.

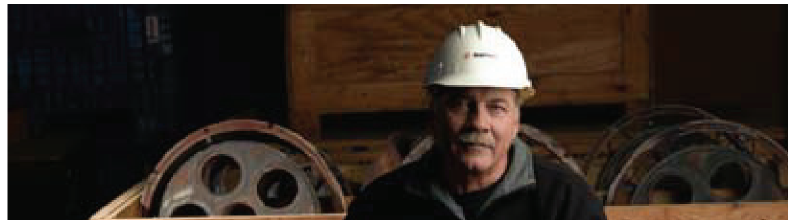
## ENVIRONMENTAL LEADERSHIP

Most satisfying of all, our major capital projects—in addition to building financial value—demonstrate our environmental leadership. Environmental issues such as global climate change represent some of the toughest challenges and public policy concerns that our industry has ever experienced. Meeting them will require new ways of producing, managing and delivering energy while maintaining reliability and competitive prices. In the long run, our environmental strategy contributes to our growth prospects, increases reliability and ultimately lowers costs.

In 2007, we made important strides in addressing environmental challenges when we filed resource plans in Minnesota and Colorado that outline how Xcel Energy will meet future energy demand and legislative requirements. For the first time ever, our resource plans described how we will reduce carbon dioxide, a greenhouse gas, by incorporating clean energy technologies in our portfolio.

Xcel Energy employee **Ty Ross**

Xcel Energy employee **Kenneth Long**



Today, in fact, Xcel Energy is the No. 1 wind power provider in the nation, with about 2,700 megawatts on line at the end of 2007 and plans to deliver about 7,400 megawatts by 2020. To leverage the value of that commitment, we also plan to own more wind facilities, including the Grand Meadow wind farm, a 100-megawatt facility in Minnesota that should be complete this year. We also operate Windsource®, which is the nation's largest voluntary wind energy program. Through the program, our customers pay a little more on their energy bills to support the development of wind power.

Solar energy is another important part of our renewable portfolio. Xcel Energy was instrumental in the construction of an 8.2-megawatt solar facility in Colorado that began operating in 2007. By 2015, we plan to bring 225 additional megawatts of solar power on line. And we offer rebates to residential and business customers for installing on-site solar systems through a program called Solar*Rewards. In 2007, we connected our 1,000th Solar*Rewards customer and expect to see hundreds of additional customers participate this year.

We're just as proud of our efforts to help customers conserve energy and manage its use. Since 1992, our customers have saved the equivalent of nine medium-sized power plants. Going forward, our energy conservation objectives are even more ambitious as we work to meet new standards in a variety of states in our service territory.

From large projects to small, technology will play a vital role in addressing global climate change. In 2007, we explored with the U.S. Department of Energy the feasibility of using wind power to create hydrogen that can generate electricity when the wind isn't blowing.

Our Renewable Development Fund will support 22 renewable energy projects selected to receive nearly $23 million in funding, and we initiated a six-month demonstration of plug-in hybrid electric vehicles to test their viability in lowering greenhouse gases.

Looking to the future, we've launched an initiative called Smart Grid that will further engage customers in controlling their energy use and helping us achieve our environmental objectives. Smart Grid benefits include reducing our carbon footprint, saving money, supporting plug-in hybrid electric vehicles and intelligent appliances and increasing the reliability of the electric grid.

Finally, we can't forget the role nuclear energy plays in achieving a clean energy future. Our Prairie Island and Monticello nuclear plants are not only safe and operationally sound, they are emission-free, which was a major factor in our decision to increase the plants' generating capacity by about 235 megawatts over the next few years. We've received the required state and federal approvals needed to extend the operating life of Monticello for 20 more years until 2030 and also are working to extend the operating licenses for the two units at Prairie Island for an additional 20 years until 2033 and 2034, respectively.

In 2007, we began to move nuclear operations that had been performed by Nuclear Management Company (NMC) to Xcel Energy. NMC, a company formed by our predecessor Northern States Power Co. and several other utilities, had operated our nuclear plants since 2000. When NMC's other owners sold their nuclear plants for a variety of reasons and left NMC, we became the sole remaining member and decided to reintegrate nuclear operations. The reintegration will be completed this year when the Nuclear Regulatory Commission approves transfer of the plants' operating licenses back to our NSP-Minnesota operating company.

Xcel Energy employee **Joy Detterer**

**CORPORATE GOVERNANCE**

That move prompted us to increase our board of directors' oversight and governance of nuclear operations, with a newly formed nuclear, environmental and safety committee. In other changes to our already strong corporate governance, we:

- Appointed a single lead director who will serve for a minimum of one year;
- Amended the Articles of Incorporation to require majority voting for directors;
- Established a resignation policy should directors not get a majority vote; and
- Initiated more stringent requirements in the Securities Trading Policy.

We've included more information on those efforts in the proxy.

**WE ARE THE ENERGY**

The real energy behind our successful initiatives comes from Xcel Energy employees, who achieved a broad range of accomplishments in 2007. Several of our power plants, for example, received safety awards from their respective states. Others set operating records. Favorable legislation, enhanced rate recovery mechanisms and the resolution of several rate cases were the result of hard work on the part of our employees.

Xcel Energy employees also contribute to their communities, which was especially evident in 2007 when we received United Way of America's Spirit of America Award. The award, which is United Way's most prestigious national accolade, recognized our commitment to community involvement. As the first utility ever to win the award, we kept the momentum going when employees and retirees pledged more than $2.2 million to support local United Way efforts, which the Xcel Energy Foundation matched dollar for dollar.

In 2007, we contributed to the community through Xcel Energy Foundation grants, in-kind donations to nonprofit organizations, matching gifts and United Way contributions. Employees also donated their time to help others.

Community support was one reason Xcel Energy was named to the Dow Jones Sustainability Index (DJSI) for North America for the second year in a row. Companies listed on the DJSI are considered to be the best in class in economic, environmental and social performance.

With excellent 2007 results, a proven and straightforward strategy and strong commitments to the environment and our communities, Xcel Energy is looking forward to a successful 2008. We are the energy—and we're putting all of it to work for you. Thank you for your trust and confidence in us.

Sincerely,

**Richard C. Kelly**
Chairman, President and CEO

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

**(Mark One)**

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

**For the Fiscal Year Ended Dec. 31, 2007**

**Or**

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

**Commission File Number 1-3034**

# Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Minnesota**<br>(State or Other Jurisdiction of Incorporation or Organization) | **41-0448030**<br>(I.R.S. Employer Identification No.) |
| **414 Nicollet Mall, Minneapolis, Minnesota**<br>(Address of Principal Executive Offices) | **55401**<br>(Zip Code) |

Registrant's Telephone Number, including Area Code (612) 330-5500

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

| Registrant | Title of Each Class | Name of Each Exchange on which Registered |
|---|---|---|
| Xcel Energy Inc. | Common Stock, $2.50 par value per share | New York |
| Xcel Energy Inc. | Rights to Purchase Common Stock, $2.50 par value per share | New York |
| | Cumulative Preferred Stock, $100 par value: | |
| Xcel Energy Inc. | Preferred Stock $3.60 Cumulative | New York |
| Xcel Energy Inc. | Preferred Stock $4.08 Cumulative | New York |
| Xcel Energy Inc. | Preferred Stock $4.10 Cumulative | New York |
| Xcel Energy Inc. | Preferred Stock $4.11 Cumulative | New York |
| Xcel Energy Inc. | Preferred Stock $4.16 Cumulative | New York |
| Xcel Energy Inc. | Preferred Stock $4.56 Cumulative | New York |
| Xcel Energy Inc. | 7.60 Junior Subordinated Notes, Series due 2068 | New York |

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Act. (Check one): ☒ Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

As of June 30, 2007, the aggregate market value of the voting common stock held by non-affiliates of the Registrant was $8,587,360,038 and there were 419,509,528 shares of common stock outstanding. Yes ☐ No ☒

As of Feb. 14, 2008, there were 429,147,979 shares of common stock outstanding, $2.50 par value.

**DOCUMENTS INCORPORATED BY REFERENCE**

The Registrant's Definitive Proxy Statement for its 2008 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

# TABLE OF CONTENTS

## Index

# PART I

## Item 1 — Business

## DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

| | |
|---|---|
| ***Xcel Energy Subsidiaries and Affiliates (current and former)*** | |
| Cheyenne | Cheyenne Light, Fuel and Power Company, a Wyoming corporation |
| Eloigne | Eloigne Co., invests in rental housing projects that qualify for low-income housing tax credits |
| NCE | New Century Energies, Inc. |
| NRG | NRG Energy, Inc., a Delaware corporation and independent power producer |
| NMC | Nuclear Management Company, a wholly owned subsidiary of NSP Nuclear Corporation |
| NSP-Minnesota | Northern States Power Company, a Minnesota corporation |
| NSP-Wisconsin | Northern States Power Company, a Wisconsin corporation |
| PSCo | Public Service Company of Colorado, a Colorado corporation |
| PSRI | PSR Investments, Inc., a manager of corporate-owned life insurance policies |
| SPS | Southwestern Public Service Co., a New Mexico corporation |
| UE | Utility Engineering Corporation, an engineering, construction and design company |
| utility subsidiaries | NSP-Minnesota, NSP-Wisconsin, PSCo, SPS |
| WGI | WestGas Interstate, Inc., a Colorado corporation operating an interstate natural gas pipeline |
| WYCO | WYCO Development LLC |
| Xcel Energy | Xcel Energy Inc., a Minnesota corporation |
| ***Federal and State Regulatory Agencies*** | |
| CPUC | Colorado Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of PSCo's operations in Colorado. The CPUC also has jurisdiction over the capital structure and issuance of securities by PSCo. |
| DOE | United States Department of Energy |
| EPA | United States Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission. The U.S. agency that regulates the rates and services for transportation of electricity and natural gas; the sale of wholesale electricity, in interstate commerce, including the sale of electricity at market-based rates; hydroelectric generation licensing; and accounting requirements for utility holding companies, service companies, and public utilities. |
| IRS | Internal Revenue Service |
| MPSC | Michigan Public Service Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Wisconsin's operations in Michigan. |
| MPUC | Minnesota Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in Minnesota. The MPUC also has jurisdiction over the capital structure and issuance of securities by NSP-Minnesota. |
| NERC | North American Electric Reliability Council |
| NMPRC | New Mexico Public Regulation Commission. The state agency that regulates the retail rates and services and other aspects of SPS' operations in New Mexico. The NMPRC also has jurisdiction over the issuance of securities by SPS. |
| NDPSC | North Dakota Public Service Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in North Dakota. |
| NRC | Nuclear Regulatory Commission. The federal agency that regulates the operation of nuclear power plants. |
| OCC | Colorado Office of Consumer Counsel. |
| PSCW | Public Service Commission of Wisconsin. The state agency that regulates the retail rates, services, securities issuances and other aspects of NSP-Wisconsin's operations in Wisconsin. |
| PUCT | Public Utility Commission of Texas. The state agency that regulates the retail rates, services and other aspects of SPS' operations in Texas. |
| SDPUC | South Dakota Public Utilities Commission. The state agency that regulates the retail rates, services and other aspects of NSP-Minnesota's operations in South Dakota. |
| WDNR | Wisconsin Department of Natural Resources |
| SEC | Securities and Exchange Commission |
| ***Electric, Purchased Gas and Resource Adjustment Clauses*** | |
| AQIR | Air-quality improvement rider. Recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan to reduce emissions and improve air quality in the Denver metro area. |
| DSM | Demand-side management. Energy conservation, weatherization and other programs to conserve or manage energy use by customers. |
| DSMCA | Demand-side management cost adjustment. A clause permitting PSCo to recover demand-side management costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. Costs for the low-income energy assistance program are recovered through the DSMCA. |

| | |
|---|---|
| ECA | Retail electric commodity adjustment. The ECA, effective Jan. 1, 2007, is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. It encourages cost reductions through purchases of economical short-term energy. The ECA also provides for an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate. The ECA mechanism will be revised quarterly and interest will accrue monthly on the average deferred balance. The ECA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010. |
| FCA | Fuel clause adjustment. A clause included in electric rate schedules that provides for monthly rate adjustments to reflect the actual cost of electric fuel and purchased energy compared to a prior forecast. The difference between the electric costs collected through the FCA rates and the actual costs incurred in a month are collected or refunded in a subsequent period. |
| GCA | Gas cost adjustment. Allows PSCo to recover its actual costs of purchased natural gas and natural gas transportation. The GCA is revised monthly to coincide with changes in purchased gas costs. |
| PCCA | Purchased capacity cost adjustment. Allows PSCo to recover from customers purchased capacity payments to power suppliers under specifically identified power purchase agreements not included in the determination of PSCo's base electric rates or other recovery mechanisms. This clause expired in 2006. A new PCCA clause became effective Jan. 1, 2007, which permits recovery from retail customers for all purchased capacity payments to power suppliers. Capacity charges are not included in PSCo's base electric rates or other recovery mechanisms. |
| PGA | Purchased gas adjustment. A clause included in NSP-Minnesota's and NSP-Wisconsin's retail natural gas rate schedules that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas and natural gas transportation. The annual difference between the natural gas costs collected through PGA rates and the actual natural gas costs is collected or refunded over the subsequent period. |
| QSP | Quality of service plan. Provides for bill credits to retail customers if the utility does not achieve certain operational performance targets and/or specific capital investments for reliability. The current QSP for PSCo and SPS electric utility expired in 2006. A new QSP for the PSCo electric utility provides for bill credit to customers based upon operational performance standards through Dec. 31, 2010. The QSP for the PSCo natural gas utility expires December 2007. |
| SCA | Steam cost adjustment. Allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA is revised annually to coincide with changes in fuel costs. |
| TCR | Transmission cost recovery adjustment. Allows NSP-Minnesota to recover the cost of transmission facilities not included in the determination of NSP-Minnesota's base electric rates in retail electric rates in Minnesota. The TCR was approved by the MPUC in 2006 to be effective in 2007, and will be revised annually as new transmission investments and costs are incurred. |

*Other Terms and Abbreviations*

| | |
|---|---|
| AFDC | Allowance for funds used during construction. Defined in regulatory accounts as a non-cash accounting convention that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in property accounts and included in income. |
| ALJ | Administrative law judge. A judge presiding over regulatory proceedings. |
| ARO | Asset Retirement Obligation |
| BART | Best Available Retrofit Technology |
| $CO_2$ | Carbon dioxide |
| C20 | Derivatives Implementation Group of FASB Implementation Issue No. C20. Clarified the terms clearly and closely related to normal purchases and sales contracts, as included in SFAS No. 133. |
| CAIR | Clean Air Interstate Rule |
| CAMR | Clean Air Mercury Rule |
| CAPCD | Colorado Air Pollution Control Division |
| COLI | Corporate-owned life insurance |
| decommissioning | The process of closing down a nuclear facility and reducing the residual radioactivity to a level that permits the release of the property and termination of license. Nuclear power plants are required by the NRC to set aside funds for their decommissioning costs during operation. |
| derivative instrument | A financial instrument or other contract with all three of the following characteristics:<br>• An underlying and a notional amount or payment provision or both,<br>• Requires no initial investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors, and<br>• Terms require or permit a net settlement, can be readily settled net by means outside the contract or provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement |
| distribution | The system of lines, transformers, switches and mains that connect electric and natural gas transmission systems to customers. |
| EPS | Earnings per share of common stock outstanding |
| ERISA | Employee Retirement Income Security Act |
| FASB | Financial Accounting Standards Board |
| FTRs | Financial Transmission Rights |
| GAAP | Generally accepted accounting principles |

| | |
|---|---|
| generation | The process of transforming other forms of energy, such as nuclear or fossil fuels, into electricity. Also, the amount of electric energy produced, expressed in megawatts (capacity) or megawatt hours (energy). |
| GHG | Greenhouse Gas |
| JOA | Joint operating agreement among the utility subsidiaries |
| LIBOR | London Interbank Offered Rate |
| LNG | Liquefied natural gas. Natural gas that has been converted to a liquid. |
| mark-to-market | The process whereby an asset or liability is recognized at fair value. |
| MERP | Metropolitan Emissions Reduction Project |
| MGP | Manufactured gas plant |
| MISO | Midwest Independent Transmission System Operator, Inc. |
| Moody's | Moody's Investor Services Inc. |
| MPCA | Minnesota Pollution Control Agency |
| native load | The customer demand of retail and wholesale customers whereby a utility has an obligation to serve: e.g., an obligation to provide electric or natural gas service created by statute or long-term contract. |
| natural gas | A naturally occurring mixture of gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane. |
| NOx | Nitrogen oxide |
| nonutility | All items of revenue, expense and investment not associated, either by direct assignment or by allocation, with providing service to the utility customer. |
| PBRP | Performance-based regulatory plan. An annual electric earnings test, an electric quality of service plan and a natural gas quality of service plan established by the CPUC. |
| PFS | Private Fuel Storage, LLC. A consortium of private parties (including NSP-Minnesota) working to establish a private facility for interim storage of spent nuclear fuel. |
| PUHCA | Public Utility Holding Company Act of 1935. Enacted to regulate the corporate structure and financial operations of utility holding companies. |
| PUHCA 2005 | Public Utility Holding Company Act of 2005. Successor to the Public Utility Holding Company Act of 1935. Eliminates most federal regulation of utility holding companies. Transfers other regulatory authority from the SEC to the FERC. |
| QF | Qualifying facility. As defined under the Public Utility Regulatory Policies Act of 1978, a QF sells power to a regulated utility at a price equal to that which it would otherwise pay if it were to build its own power plant or buy power from another source. |
| rate base | The investor-owned plant facilities for generation, transmission and distribution and other assets used in supplying utility service to the consumer. |
| ROE | Return on equity |
| RTO | Regional Transmission Organization. An independent entity, which is established to have "functional control" over a utility's electric transmission systems, in order to provide non-discriminatory access to transmission of electricity. |
| SFAS | Statement of Financial Accounting Standards |
| $SO_2$ | Sulfur dioxide |
| SPP | Southwest Power Pool, Inc. |
| Standard & Poor's | Standard & Poor's Ratings Services |
| TEMT | Transmission and Energy Markets Tariff of MISO |
| TCEQ | Texas Commission of Environmental Quality |
| unbilled revenues | Amount of service rendered but not billed at the end of an accounting period. Cycle meter-reading practices result in unbilled consumption between the date of last meter reading and the end of the period. |
| underlying | A specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event such as a scheduled payment under a contract. |
| VaR | Value-at-risk |
| wheeling or transmission | An electric service wherein high-voltage transmission facilities of one utility system are used to transmit power generated within or purchased from another system. |
| working capital | Funds necessary to meet operating expenses. |

***Measurements***

| | |
|---|---|
| Btu | British thermal unit. A standard unit for measuring thermal energy or heat commonly used as a gauge for the energy content of natural gas and other fuels. |
| Bcf | Billion cubic feet |
| GWh | Gigawatt hours |
| KV | Kilovolts |
| KW | Kilowatts (one KW equals one thousand watts) |
| Kwh | Kilowatt hours |
| Mcf | Thousand cubic feet |
| MMBtu | One million Btus |
| MW | Megawatts (one MW equals one thousand KW) |
| Watt | A measure of power production or usage. |
| Volt | The unit of measurement of electromotive force. Equivalent to the force required to produce a current of one ampere through a resistance of one ohm. The unit of measure for electrical potential. Generally measured in kilovolts or KV. |

# COMPANY OVERVIEW

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2007, Xcel Energy's continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a company formed to develop and lease new natural gas pipeline and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.

Xcel Energy was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its web site address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its web site, its annual report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. In addition, the Xcel Energy guidelines on Corporate Governance and Code of Conduct are also available on its web site.

As discussed in detail in the Management's Discussion and Analysis section, environmental leadership is a core strategic priority for Xcel Energy. Our environmental leadership strategy is designed to meet customer and policy maker expectations while creating shareholder value. We have established a highly effective environmental compliance program and have produced an excellent compliance record. Moreover, we pursue environmental policy initiatives that promote our environmental leadership and provide growth opportunities. Among other things, Xcel Energy is a national leader in voluntary emission reduction programs, the nation's largest retail utility wind energy provider and a leader in innovative technology, energy efficiency and conservation and customer-driven renewable energy programs. In 2007, Xcel Energy filed resource plans in two of its operating service territories that will result in a significant reduction in $CO_2$ emissions, while meeting growing customer demand at a reasonable price. Through our environmental leadership strategy, we are well-positioned to meet the challenges of potential future climate change regulation, comply with the renewable energy mandates and take advantage of the clean energy incentives created by policy makers in the states in which we operate.

## NSP-Minnesota

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately 10 percent of the total sales in 2007. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 90 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2007. Generally, NSP-Minnesota's earnings comprise approximately 40 percent to 50 percent of Xcel Energy's consolidated net income.

The electric production and transmission system of NSP-Minnesota is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System. The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved agreement between the two companies, called the Interchange Agreement, provides for the sharing of all costs of generation and transmission facilities of the NSP System, including capital costs.

NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; and NSP Nuclear Corp., which owns NMC.

## NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. The wholesale customers served by NSP-Wisconsin comprised approximately 8 percent of the total sales in 2007. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in the same service territory. NSP-Wisconsin provides electric utility service to approximately 246,000 customers and natural gas utility service to approximately 102,000 customers. The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota, as discussed previously. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2007. Generally, NSP-Wisconsin's earnings comprise approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

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

## PSCo

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 24 percent of the total sales in 2007. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility and natural gas utility service to approximately 1.3 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2007. Generally, PSCo's earnings comprise approximately 40 percent to 50 percent of Xcel Energy's consolidated net income.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc., which owns certain real estate interests for PSCo; and Green and Clear Lakes Company, which owns water rights. PSCo also owned PSRI, which held certain former employees' life insurance policies. Following settlement with the IRS during 2007, such policies were terminated. PSCo also holds a controlling interest in several other relatively small ditch and water companies.

## SPS

SPS was incorporated in 1921 under the laws of New Mexico. SPS is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 38 percent of the total sales in 2007. SPS provides electric utility service to approximately 388,000 customers. Approximately 76 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2007. Generally, SPS' earnings comprise approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

## Other Subsidiaries

WGI was incorporated in 1990 under the laws of Colorado. WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to the Cheyenne system near Cheyenne, Wyo.

In 1999, WYCO was jointly formed with a subsidiary of El Paso Corporation to develop and lease new natural gas pipeline and compression facilities. Xcel Energy plans to invest approximately $151 million in WYCO between 2007 and 2010. The WYCO pipeline project is expected to begin operations in 2008 and the WYCO storage project is expected to begin operations in 2009. The new pipeline and storage projects will be leased to Colorado Interstate Gas Company, a subsidiary of El Paso Corporation. The terms of the lease agreement for the new pipeline and storage projects will be based on FERC regulation and it is anticipated that they will be approved by the FERC as a component of the certificate filing to be made by the Colorado Interstate Gas Company.

Xcel Energy Services Inc. is the service company for the Xcel Energy holding company system, where corporate financing activity occurs. Generally, Xcel Energy Services, Inc.'s losses comprise approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

Xcel Energy's nonregulated subsidiary in continuing operations is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

See financial information regarding the segments of Xcel Energy's business at Note 18 to the consolidated financial statements.

In the past, Xcel Energy had several other subsidiaries that were sold or divested. For more information regarding Xcel Energy's discontinued operations, see Note 3 to the consolidated financial statements.

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. Comparative segment revenues, income from continuing operations and related financial information for fiscal years 2007, 2006 and 2005 are set forth in Note 18 to the accompanying consolidated financial statements.

Xcel Energy focuses on growing through investments in electric and natural gas rate base to meet growing customer demands, environmental and renewable energy initiatives and to maintain or increase reliability and quality of service to customers. Xcel Energy files periodic rate cases with state and federal regulators to earn a return on its investments and recover costs of operations. For more information regarding Xcel Energy's capital expenditures, see Note 15 to the consolidated financial statements.

# ELECTRIC UTILITY OPERATIONS

## Electric Utility Trends

### Overview

***Climate Change and Clean Energy* —** Like most other utilities, Xcel Energy is subject to a significant array of environmental regulations focused on many different aspects of its operations. There are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. Xcel Energy's electric generating facilities are likely to be subject to regulation under climate change policies introduced at either the state or federal level within the next few years. Several of the states in which we operate have proposed or implemented clean energy policies, such as renewable energy portfolio standards or DSM programs, in part designed to reduce the emissions of GHGs. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies. Xcel Energy is advocating with state and federal policy makers for climate change and clean energy policies that will result in significant long-term reduction in GHG emissions, develop low-emitting technologies and secure, cost-effective energy supplies for our customers and our nation.

While Xcel Energy is not currently subject to state or federal limits on its GHG emissions, we have undertaken a number of initiatives to prepare for climate change regulation and reduce our GHG emissions. These initiatives include emission reduction programs, energy efficiency and conservation programs, renewable energy development and technology exploration projects. Although the impact of climate change policy on Xcel Energy will depend on the specifics of state and federal policies and legislation, we believe that, based on prior state commission practice, we would be granted the authority to recover the cost of these initiatives through rates.

Additional information regarding climate change and clean energy is presented in the Management's Discussion and Analysis section.

***Utility Restructuring and Retail Competition* —** The FERC has continued with its efforts to promote more competitive wholesale markets through open-access transmission and other means. As a consequence, Xcel Energy's utility subsidiaries and their wholesale customers can purchase from competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to the utility subsidiaries' to serve their native load.

Xcel Energy supports the continued development of wholesale competition and non-discriminatory wholesale open access transmission services. Xcel Energy will continue to work with the SPP on RTO development for the Texas Panhandle region and the incorporation of independent transmission operations to insure non-discriminatory open access. Xcel Energy is also still pursuing strengthening its transmission system internally to alleviate north and south congestion within the Texas Panhandle and other lines to increase the transfer capability between the Texas Panhandle and other electric systems.

One state served by Xcel Energy's utility subsidiaries has implemented retail electric utility competition. In 2002, Texas implemented retail competition, but it is presently limited to utilities within the Electric Reliability Council of Texas (ERCOT), which does not include SPS. Under current law, SPS can file a plan to implement competition, subject to regulatory approval, in Texas. Local market conditions and political realities must be considered in proposing the transition to competition. Xcel Energy has been unable to develop a plan for the Texas Panhandle to move toward competition that would be in the best interests of its customers. As a result, Xcel Energy does not plan to propose retail competition in the Texas Panhandle until required by law. New Mexico repealed its legislation related to retail electric utility competition.

In 2002, NSP-Wisconsin began providing its Michigan electric customers with the opportunity to select an alternative electric energy provider. To date, no NSP-Wisconsin customers have selected an alternative electric energy provider.

Xcel Energy's retail electric business faces competition as industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas or steam/chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. While each of Xcel Energy's utility subsidiaries faces these challenges, their rates are competitive with currently available alternatives.

### Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel

Energy's utility subsidiaries. State and local agencies have jurisdiction over many of Xcel Energy's utility activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 14 to the consolidated financial statements for a discussion of other regulatory matters.

***FERC Rules Implementing Energy Policy Act of 2005 (Energy Act)*** — The Energy Act repealed PUHCA effective Feb. 8, 2006. In addition, the Energy Act required the FERC to conduct several rulemakings to adopt new regulations to implement various aspects of the Energy Act. Since August 2005, the FERC has completed several rulemaking proceedings to modify its regulations on a number of subjects, including:

- Adopting regulations to establish a national Electric Reliability Organization (ERO) to replace the voluntary NERC structure, and requiring the ERO to establish mandatory electric reliability standards and imposition of financial or other penalties for violations of adopted standards;
- Certifying the NERC as the ERO and adopting rules making 83 NERC reliability standards mandatory and subject to potential financial penalties up to $1 million per day per violation for non-compliance effective June 18, 2007; and approving delegation agreements between NERC and various regional entities, including the Midwest Reliability Organization (MRO), SPP and Western Electricity Coordinating Council (WECC), whereby the regional entities will be responsible for regional enforcement of approved NERC standards. On Dec. 21, 2007, the FERC approved seven additional NERC mandatory standards to be effective in first quarter 2008;
- Adopting rules allowing utilities in organized wholesale energy markets such as MISO and SPP to seek to eliminate their mandatory Public Utility Regulatory Policies Act (PURPA) QF power purchase obligations; and
- Adopting rules to establish incentives for investment in new electric transmission infrastructure.

During 2007, both state and federal legislative initiatives were introduced, with the Xcel Energy subsidiaries taking an active role in their development.

While Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement these new rules and regulations as they become effective.

***Electric Transmission Rate Regulation*** — The FERC regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control of their electric transmission assets and the related responsibility for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO RTO. SPS is a member of the SPP RTO. Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates. PSCo is currently participating with other utilities in the development of WestConnect, which would provide certain regionalized transmission and wholesale energy market functions but would not be an RTO.

On Feb. 15, 2007, the FERC issued final rules (Order No. 890) adopting revisions to its open access transmission service rules. Xcel Energy submitted the required compliance revisions to its Open Access Transmission Tariff (OATT) on July 13, 2007, Sept. 11, 2007 and Dec. 7, 2007, as required. The compliance filings are pending FERC action. On Dec. 28, 2007, the FERC issued an order on rehearing making certain modifications to Order No. 890. The revised rules will be effective in March 2008. Xcel Energy is now reviewing the amended final rules.

In addition, in January 2007, the FERC issued interim and proposed rules to modify the current FERC standards of conduct rules governing the functional separation of the Xcel Energy electric transmission function from the wholesale sales and marketing function. The proposed rules are pending final FERC action.

While Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement these new rules and regulations as they become effective.

***Centralized Regional Wholesale Markets*** — The FERC rules allow RTOs to operate centralized regional wholesale energy markets. On April 1, 2005, MISO began operation of a "Day 2" regional day-ahead and real time wholesale energy market. MISO uses security constrained regional economic dispatch and congestion management using Locational Marginal Pricing (LMP) and FTRs. The Day 2 market is intended to provide more efficient generation dispatch over the 15 state MISO region, including the NSP System. In 2007, SPP began operation of an Energy Imbalance Service (EIS) market, which will provide a more limited wholesale energy market for the region that includes the SPS system.

On Sept. 14, 2007, MISO filed for FERC approval to establish a centralized regional wholesale ancillary services market (ASM) in the second quarter of 2008. The ASM is intended to provide further efficiencies in generation dispatch by allowing for regional regulation response and contingency reserve services through a bid-based market mechanism co-optimized with the Day 2 energy market. In addition, MISO would consolidate the operation of approximately 20 existing NERC approved balancing authorities (the entity responsible for maintaining reliable operations for a defined geographic region) into a single regional balancing authority. Xcel Energy generally supports implementation of the ASM, because it is expected to allow native NSP System generation to be used more efficiently, as certain generation will not always need to be held in reserve, and to facilitate the operation of intermittent wind generation on the NSP System required to achieve state-mandated renewable energy supply standards. Comments on the ASM proposal were filed on Oct. 15, 2007, and the FERC held a technical conference on certain market power issues in November 2007. The proposal is pending FERC action. If the FERC approves the ASM tariff in February 2008 without material conditions, and if MISO can demonstrate system and operation readiness, MISO would implement the ASM on June 1, 2008. If approved by the FERC, NSP-Minnesota and NSP-Wisconsin expect to file for state regulatory approvals, as necessary, to recover ASM costs via their fuel and purchased energy cost recovery mechanisms in first quarter 2008.

In another development affecting regional wholesale markets, in December 2007, MISO and some MISO transmission owners, including NSP-Minnesota and NSP-Wisconsin, filed proposed changes to the MISO TEMT affecting the revenue distribution of transmission revenues. Without the proposed tariff change, certain MISO transmission owners would experience an increase in prospective transmission revenues, while the revenues to other MISO transmission owners would correspondingly decrease. The proposed change did not affect 2007 results, but would essentially preserve the historic allocation of transmission service revenues in 2008 and future years. In December 2007, Ameren-Union Electric (Ameren UE) protested the proposed change. In February 2008, the FERC issued an order accepting the MISO tariff change effective February 2008 and rejecting the Ameren-UE protest.

***Market Based Rate Rules* —** In June 2007, the FERC issued a final order governing its market-based rate authorizations to electric utilities. The FERC reemphasized its commitment to market-based pricing, but is revising the tests it uses to assess whether a utility has market power and has emphasized that it intends to exercise greater oversight where it has market-based rate authorizations. Each of the Xcel Energy operating companies has been granted market-based rate authority and will be subject to the new rule.

An aspect of the FERC's market-based rate requirements is the requirement to charge mitigated rates in markets where a utility is found to have market power. PSCo and SPS have been authorized by the FERC to charge market-based rates outside of their control areas, but are generally limited to charging mitigated rates within their control areas. PSCo and SPS use cost-based rate caps set out in the Western Systems Power Pool (WSPP) agreement as their applicable mitigated rates, an approach approved by the FERC. However, concurrently with the issuance of the final order, the FERC initiated a proceeding to investigate whether the use of the WSPP rate caps for this purpose is just and reasonable. An outcome of this proceeding may be to lower the mitigated rates that PSCo and SPS may charge in their control areas.

## NSP-Minnesota

### Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction* —** Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC has regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, property transfers, mergers and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need for generating plants greater than 50 MW and transmission lines greater than 100 KV.

No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over the need for certain generating and transmission facilities, and the siting and routing of certain new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale and the transmission of electricity in interstate commerce. NSP-Minnesota has received authorization from the FERC to make wholesale electric sales at market-based prices (see market-based rate authority discussion) and is a transmission-owner member of the MISO RTO.

***Fuel, Purchased Energy and Conservation Cost Recovery Mechanisms* —** NSP-Minnesota's retail electric rate schedules in Minnesota, North Dakota and South Dakota include a FCA that provides for monthly adjustments to billings and revenues for changes in prudently incurred cost of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms individually approved by the regulators in each jurisdiction.

The FCA mechanisms allow NSP-Minnesota to bill customers for the cost of fuel and fuel related costs used to generate electricity at its plants and energy purchased from other suppliers. In December 2006, the MPUC authorized FCA recovery of all MISO Day 2 charges, except certain administrative charges, which NSP-Minnesota is partially recovering in base rates and partially deferring for future recovery. In general, capacity costs are not recovered through the FCA. NSP-Minnesota's electric wholesale customers also have a FCA provision in their contracts.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue on conservation improvement programs. These costs are recovered through an annual cost recovery mechanism for electric conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually. While this law will change to a savings-based requirement beginning in 2010, the costs of providing qualified conservation improvement programs will continue to be recoverable through a rate adjustment mechanism.

***MERP Rider Regulation*** — In December 2003, the MPUC approved NSP-Minnesota's MERP proposal to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. The first MERP project at the A. S. King plant went into service in July 2007 with the remaining two projects (High Bridge and Riverside) expected to begin operations in 2008 and 2009, respectively, at a cumulative investment of approximately $1 billion. The MPUC approved a rate rider to recover prudent costs of the projects from Minnesota customers beginning Jan. 1, 2006, including a rate of return on the construction work in progress. The MPUC approval has a sliding ROE scale based on actual construction cost compared with a target level of construction costs (based on an equity ratio of 48.5 percent and debt of 51.5 percent) to incentivize NSP-Minnesota to control construction costs. At Dec. 31, 2007, the estimated ROE was 10.7 percent, based on construction progress to date.

| Actual Costs as a Percent of Target Costs | ROE |
|---|---|
| Less than or equal to 75% | 11.47% |
| Over 75% and up through 85% | 11.22 |
| Over 85% and up through 95% | 11.00 |
| Over 95% and up through 105% | 10.86 |
| Over 105% and up through 115% | 10.55 |
| Over 115% and up through 125% | 10.22 |
| Over 125% | 9.97 |

## Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2008, assuming normal weather, are listed below.

| | System Peak Demand (in MW) | | | |
|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 Forecast |
| NSP System | 9,104 | 9,859 | 9,427 | 9,737 |

The peak demand for the NSP System typically occurs in the summer. The 2007 system peak demand for the NSP System occurred on July 26, 2007.

## Energy Sources and Related Transmission Initiatives

NSP-Minnesota expects to use existing electric generating stations, power purchases, DSM options, new generation facilities and phased expansion of existing generation at select power plants to meet its system capacity requirements.

***Purchased Power*** — NSP-Minnesota has contractual arrangements to purchase power from other utilities and independent power producers. Capacity is the measure of the rate at which a particular generating source produces electricity. Energy is a measure of the amount of electricity produced from a particular generating source over a period of time. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

NSP-Minnesota also makes short-term purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to comply with minimum availability requirements, to obtain energy at a lower cost and for various other operating requirements.

***Purchased Transmission Services*** — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contractual arrangements with MISO and regional transmission service providers to deliver power and energy to the NSP System for native load customers, which are retail and wholesale load obligations with terms of more than one year.

***Excelsior Energy Inc. (Excelsior) —*** In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration that NSP-Minnesota be compelled to enter into an agreement to purchase the output from two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota as part of the Mesaba Energy Project. Excelsior filed this petition making claims pursuant to Minnesota statutes relating to an Innovative Energy Project and Clean Energy Technology. NSP-Minnesota opposed the petition.

The MPUC referred this matter to a contested case hearing before an ALJ to act on Excelsior's petition. The contested case proceeding considered a 600 MW unit in phase I and a second 600 MW unit in phase II of the Mesaba Energy Project.

The MPUC issued its order for phase 1 of the hearing on Aug. 30, 2007. In it, the MPUC found that:

- The Mesaba Energy Project is an innovative energy project under the applicable statute;
- The terms and conditions of the proposed purchase power agreement are inconsistent with the public interest and are denied;
- Excelsior and NSP-Minnesota should resume negotiations towards an acceptable purchase power agreement, with assistance from the Minnesota Department of Commerce (MDOC) and the guidance provided by the order; and
- The MPUC will explore a statewide market for the output of this project.

The MPUC denied rehearing, except for certain clarifications and requiring status reports on negotiations Excelsior appealed the MPUC's decision in December 2007. The Minnesota Court of Appeals dismissed the appeal as premature because the MPUC's order on phase I is not final agency action on the entire case.

Meanwhile, the ALJ issued a decision in Phase 2 of this proceeding, recommending denial of Excelsior's proposed purchase power agreement for a second IGCC project. Exceptions and replies have been filed. The MPUC is expected to take up this matter in 2008.

***Greenhouse Gas Emissions —*** The 2007 Minnesota legislature adopted the goal to reduce statewide GHG emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.

The legislation prohibits the construction within Minnesota of a new large energy facility, the import or commitment to import from outside Minnesota power from a new large energy facility, or entering into a new long-term power purchase agreement that would increase statewide power sector $CO_2$ emissions. The statute does not impose limitations on $CO_2$ or other GHG emissions on NSP-Minnesota and provided certain exemptions. On Feb. 1, 2008, the MDOC submitted to the legislature a climate change action plan that proposes certain changes to meet the requirements of this section.

***Renewable Energy Standard —*** The 2007 Minnesota legislature adopted a Renewable Energy Standard (RES) statute requiring NSP-Minnesota to acquire 30 percent of its energy requirements by 2020 from qualifying renewable sources, of which 25 percent must be wind energy. The legislation allows all NSP-Minnesota renewable resources to count toward meeting the standard. Costs associated with complying with the standard are recoverable through automatic recovery mechanisms.

NSP-Minnesota has filed with the MPUC a renewable energy plan detailing its plans for adding wind resources. This plan seeks to achieve balance in the wind portfolio, with roughly half of new resources being owned by NSP-Minnesota and achieving roughly proportionate shares between community-based energy developments, other power purchase agreements and utility projects.

***Conservation and DSM Legislation —*** The 2007 Minnesota legislature adopted a statute establishing a statewide goal to reduce energy demand by 1.5 percent per year and fossil fuel use by 15 percent. The bill requires utilities to propose conservation and DSM programs that achieve at least 1.0 percent per year reduction in energy demand, subject to limitations regarding excessive costs for customers, reliability or other negative consequences. The statute also allows utilities to fund internal infrastructure changes that will contribute to lower energy use and provides for cost recovery outside a rate case for such projects.

***NSP System Resource Plan —*** In December, 2007, NSP-Minnesota filed its 2007 resource plan with the MPUC. The plan incorporates the actions needed to comply with expansive new legislation regarding GHG emissions control, renewable energy procurement, and DSM adopted by the 2007 Minnesota legislature. Due to the expansion of wind generation procurement and DSM obligations, the plan indicates that the type of incremental resources has changed from prior plans. Key highlights of the plan include:

- Additional wind generation resources of 2,600 MW, allowing NSP-Minnesota to comply with our RES of 30 percent renewable energy by 2020.
- Increases in DSM of approximately 30 percent energy savings and 50 percent demand savings.
- Seek license renewals for Prairie Island's two units through 2033 and 2034, respectively, and expand capacity at Prairie Island by 160 MW and Monticello by 71 MW.
- Request approval to make environmental upgrades at Sherco, while expanding capacity by 80 MW. The environmental upgrades would result in a significant reduction in overall $SO_2$, NOx and mercury emissions from the facility.
- Negotiate and seek approval of purchases from Manitoba Hydro Electric Board (Manitoba Hydro) for 375 MW of intermediate and 350 MW of peaking resources beginning in 2015.
- Incremental peaking and intermediate generation needs of 2,300 MWs.
- Carbon emission reductions of 22 percent below 2005 levels by 2020, a six million ton reduction.

The MPUC will set a schedule for consideration of the plan early in 2008.

***NSP-Minnesota Base Load Acquisition Proceeding —*** On Nov. 1, 2006, NSP-Minnesota filed a proposal with the MPUC for a purchase of 375 MW of capacity and energy from Manitoba Hydro for 2015-2025 and the purchase of 380 MW of wind energy to fulfill the base load need identified in the 2004 resource plan. An alternate supplier proposed a 375 MW share of a lignite coal generation plant to be located in North Dakota and 380 MW of wind energy generation, with an option for Xcel Energy ownership in both components. The MPUC referred the matter to a contested case proceeding.

On July 20, 2007, NSP-Minnesota filed a petition asking to suspend the proceeding until NSP-Minnesota can complete its analysis of the impact of the RES and conservation goals on its need for additional resources, as outlined in the July 20, 2007 Notice of Changed Circumstance in the Resource Plan.

In September 2007, the MPUC approved NSP-Minnesota's Notice of Changed Circumstance and required NSP-Minnesota to file a new resource plan by Dec. 14, 2007. NSP-Minnesota filed the 2007 resource plan, along with a proposal for closing this proceeding as the new plan does not indicate a base load resource need. The MPUC is expected to take up matter of schedule for the base load proceeding in early 2008.

***Additional Base Load Capacity Projects for Sherco, Monticello and Prairie Island —*** The MPUC order in the 2004 NSP-Minnesota resource plan indicated that additional capacity from the Sherco, Monticello, and Prairie Island plants would be cost-effective and should be pursued. On July 20, 2007, NSP-Minnesota filed a Notice of Changed Circumstance with the MPUC seeking to delay these proceedings until NSP-Minnesota can complete its analysis of the impact of the RES and conservation goals on its need for additional resources. In September 2007, MPUC approved the Notice of Changed Circumstance and directed NSP-Minnesota to file a new resource plan by Dec. 14, 2007. NSP-Minnesota filed the 2007 resource plan, which confirms the cost-effectiveness of these projects, and proposed to initiate filings for approval to pursue these projects in the first half of 2008.

***NSP-Minnesota Transmission Certificates of Need —*** In March 2003, the MPUC granted four certificates of need to NSP-Minnesota for the construction of various transmission system upgrades for up to 825 MW of renewable energy generation (wind and biomass) in southwest and western Minnesota.

The MPUC granted routing permits in 2004-05 for the major transmission facilities. NSP-Minnesota expects to complete the transmission construction in 2008 at a cost of approximately $230 million. As of Dec. 20, 2007, MISO has determined the new transmission facilities already installed provide transmission outlet capacity for up to 900 MW of renewable generation.

In late 2006, NSP-Minnesota filed applications for certificates of need with the MPUC for three additional transmission lines in southwestern Minnesota and one in Chisago County, Minn. In 2007, the MPUC issued a certificate of need authorizing NSP-Minnesota to construct three new 115 KV transmission lines (totaling 35 to 50 miles) in southwestern Minnesota to provide approximately 350 MW of incremental transmission delivery capacity for wind generation. The three projects, including associated substations, are expected to cost $72.5 million. The MPUC order required NSP-Minnesota to file required route permit applications by January 2008 and complete construction by Spring 2009. The route permit applications were filed with the MPUC and SDPUC as required, and are pending MPUC and SDPUC action.

In January 2008, the MPUC voted to grant NSP-Minnesota a certificate of need for the Chisago County, Minnesota project, which would replace an existing 69 KV line with 115 and 161 KV facilities and add a new substation at an estimated cost of $64 million and a route permit for the majority of the proposed line. The MPUC set the issue of the disputed route for a half-mile segment of the line for further discussions between the parties. The project would be placed in service in 2010. The PSCW has already approved construction by NSP-Wisconsin and Dairyland Power Cooperative of related 161 KV facilities in Wisconsin.

As part of CapX 2020, NSP-Minnesota and Great River Energy (on behalf of nine other regional transmission providers) filed a certificate of need application in August 2007, for three 345 KV transmission lines serving Minnesota and parts of surrounding states. The current schedule targets an MPUC order by the end of 2008 or early 2009. The three lines would include construction of approximately 700 miles of new facilities at a cost of $1.4 to $1.7 billion, with construction to be completed in phases between 2011 and 2015. The application put forth a potential ownership percentage of 36 to 72 percent for each of the three 345 KV projects for NSP System. Updated NSP-Minnesota and NSP-Wisconsin cost estimates are expected following the negotiation of project agreements outlining the terms and conditions related to construction management, ownership, operations and maintenance of these facilities.

***FCA Investigation*** — In 2003, the MPUC opened an investigation to consider the continuing usefulness of the FCAs for electric utilities in Minnesota. There was no further activity until the MPUC issued a notice for comments on April 5, 2007, as to whether to continue the statewide investigation.

Pursuant to the notice, utilities in Minnesota, the MDOC and the Minnesota Office of Attorney General (MOAG) filed initial and reply comments on April 30, 2007 and June 1, 2007, respectively. The utilities generally argued the 2003 investigation could be closed, with remaining issues addressed in the separate investigation initiated by the Dec. 20, 2006 order in the MISO Day 2 cost recovery docket. The MDOC filed comments seeking to continue the investigations. In response, the utilities filed additional comments on Sept. 28, 2007, that indicated a willingness to continue with the investigation and provide more information to both regulators and customers regarding fuel and purchased power costs, plant outages and other factors affecting fuel clause levels. Continued discussions among utilities, the MDOC, MOAG and business customers regarding appropriate FCA reporting detail and provision of additional information to customers is on going.

***Grand Meadow Wind Farm*** — In June 2007, NSP-Minnesota filed an application for a certificate of need for the Grand Meadows wind farm, a 100-MW development to be located in southeast Minnesota. The Grand Meadows project would be implemented under a build-own-transfer agreement between NSP-Minnesota and enXco, a wind project developer. Total project costs are estimated to be approximately $213 million. The MPUC approved this certificate of need and issued a site permit. Construction is expected to start in early 2008.

***Capital Structure Petition*** — In December 2007, the MPUC approved NSP-Minnesota's regular annual capital structure petition for ongoing security issuance and increased capitalization.

***Mercury Reduction and Emissions Reduction Filings*** — Pursuant to Minnesota law, in December 2007, NSP-Minnesota filed a plan with the MPCA and MPUC for reducing mercury emissions by up to 90 percent at the Sherco unit 3 and King plants. Estimated project costs amount to approximately $9.1 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco Units 1and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1 billion. The filing also contains alternatives for the MPUC to consider additional capacity and to achieve lower emissions. If selected, these alternatives could range from $90.8 million to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota's investments are subject to the MPUC approval of a cost recovery mechanism.

***Nuclear Power Operations and Waste Disposal*** — NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See additional discussion regarding the nuclear generating plants at Note 16 to the consolidated financial statements.

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

*Low-Level Radioactive Waste Disposal* — Federal law places responsibility on each state for disposal of low-level radioactive waste (LLW) generated within its borders. LLW from NSP-Minnesota's Monticello and Prairie Island nuclear plants is currently disposed at the Barnwell facility located in South Carolina (all classes of LLW) and at the Clive facility located in Utah (class A LLW only). NSP-Minnesota has an annual contract with Barnwell that is scheduled to expire on June 30, 2008, but is also able to utilize the Clive facility through various LLW processors. NSP-Minnesota has storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their current licensed lives, if off-site LLW disposal facilities were not available to NSP-Minnesota.

*High-Level Radioactive Waste Disposal* — The federal government has the responsibility to dispose of, or permanently store, domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. To date, the DOE has not accepted any of NSP-Minnesota's spent nuclear fuel. See Item 3 — Legal Proceedings and Note 15 to the consolidated financial statements for further discussion of this matter.

NSP-Minnesota has on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear plants.

- In 1993, the Prairie Island plant was licensed by the federal NRC to store up to 48 casks of spent fuel at the plant.
- In 1994, the Minnesota legislature adopted a limit on dry cask storage of 17 casks.
- In 2003, the Minnesota legislature enacted revised legislation that will allow NSP-Minnesota to continue to operate the facility and store spent fuel there until its current licenses with the NRC expire in 2013 and 2014. The legislation transfers the primary authority concerning future spent-fuel storage issues from the state legislature to the MPUC. It also allows for additional storage without the requirement of an affirmative vote from the state legislature, if the NRC extends the licenses of the Prairie Island and Monticello plants and the MPUC grants a certificate of need for such additional storage. It is estimated that operation through the end of the current license will require 12 additional storage casks to be stored at Prairie Island, for a total of 29 casks.
- In October 2006, the MPUC authorized an on-site storage facility and 30 casks at Monticello, which will allow the plant to operate to 2030. The MPUC decision was effective June 1, 2007.
- As of Dec. 31, 2007, there were 24 casks loaded and stored at the Prairie Island plant.

See Note 16 in the consolidated financial statements for further discussion of the matter.

*PFS* — NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 1997, PFS filed a license application with the NRC for a temporary storage site for spent nuclear fuel on the Skull Valley Indian Reservation in Utah. In February 2006, the NRC commissioners issued the license for PFS. The license is contingent on the condition that PFS must demonstrate that it has adequate funding before construction may begin. In December 2005, the U.S. Supreme Court denied Utah's petition for a writ of certiorari to hear an appeal of a lower court's ruling on a series of state statutes aimed at blocking the storage and transportation of spent fuel to PFS. Also in December 2005, NSP-Minnesota indicated that it would hold in abeyance future investments in the construction of PFS as long as there is apparent and continuing progress in federally sponsored initiatives for storage, reuse, and/or disposal for the nation's spent nuclear fuel. In September 2006, the Department of the Interior issued two findings: (1) that it would not grant the leases for rail or intermodal sites and (2) that it was revoking its previous conditional approval of the site lease between PFS and the Skull Valley Indian tribe even though the conditions had been met. The stated reasons were principally lack of progress at Yucca Mountain and lack of Bureau of Indian Affairs staff to monitor this activity. Both findings are expected to be appealed.

*Prairie Island Steam Generator Replacement* — Prairie Island Unit 2 steam generators received required inspections during a scheduled 2005 outage. Based on current rates of degradation and available repair processes, NSP-Minnesota plans to replace these steam generators in the 2013 refueling outage.

*NSP-Minnesota Nuclear Plant Re-licensing* — Monticello's renewed license expires in 2030, and Prairie Island's licenses for its two units expire in 2013 and 2014. NRC approved Monticello's renewed license in November 2006, and the MPUC order approving additional spent fuel storage to support twenty additional years of operation went into effect on June 1, 2007. Prairie Island has initiated the necessary plant assessments and aging analysis to support submittal of similar applications to the NRC and the MPUC, currently planned for submittal in early 2008.

*Nuclear Plant Power Uprates* — NSP-Minnesota is seeking approval to increase the capacity of all three nuclear units that will total approximately 235 MW, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2's original steam generators, currently planned for replacement during the refueling outage in 2013. Capital investments for life cycle management and power uprate activities through 2007 have totaled approximately $40 million. For the years 2008 through 2015, spending is estimated at $1.1 billion. NSP-Minnesota plans to seek approval for an alternative recovery mechanism from customers of its nuclear costs. NSP-Minnesota plans to submit the certificate of need for the Monticello uprate and the certificate of need for the Prairie Island uprate in the first quarter of 2008.

*NMC* — On Sept. 28, 2007, Xcel Energy obtained 100 percent ownership in NMC as a result of Wisconsin Energy Corporation (WEC) exiting the partnership due to the sale of its Point Beach Nuclear Plant to FPL Energy. Accordingly, the results of operations of NMC and the estimated fair value of assets and liabilities were consolidated in Xcel Energy's consolidated financial statements from the Sept. 28, 2007, transaction date. WEC was required to pay an exit fee and surrender all of its equity interest in NMC upon exiting. The effect of this transaction was not material to the financial position or the results of operations to Xcel Energy. Xcel Energy is in the process of reintegrating its nuclear operations into its generation operations and applying to the NRC to transfer the nuclear operating licenses from NMC to NSP-Minnesota. The transfer of licenses is expected to be completed in 2008.

For further discussion of nuclear obligations, see Note 16 to the consolidated financial statements.

## Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

| NSP System | Coal* | | Nuclear | | Natural Gas | | Average Fuel |
|---|---|---|---|---|---|---|---|
| Generating Plants | Cost | Percent | Cost | Percent | Cost | Percent | Cost |
| 2007 | $1.56 | 57% | $0.51 | 38% | $7.60 | 4% | $1.47 |
| 2006 | 1.12 | 59 | 0.46 | 38 | 7.28 | 3 | 1.08 |
| 2005 | 1.04 | 60 | 0.46 | 36 | 8.32 | 3 | 1.11 |

* Includes refuse-derived fuel and wood

***Fuel Sources*** — The NSP System normally maintains approximately 30 days of coal inventory at each plant site. Coal inventory levels, however, may vary widely among plants. Coal supply inventories at Dec. 31, 2007, were approximately 47 days usage, based on the maximum burn rate for all of NSP-Minnesota's coal-fired plants. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under long-term contracts with suppliers operating in Wyoming and Montana. Estimated coal requirements at NSP-Minnesota and NSP-Wisconsin's major coal-fired generating plants are approximately 12.4 million tons per year.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide approximately 100 percent of its coal requirements in 2008, 63 percent of its coal requirements in 2009 and 39 percent of its coal requirements in 2010. Any remaining requirements will be filled through a request for proposal (RFP) process according to the fuel supply operations procurement strategy.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of approximately 100 percent of 2008, 2009 and 2010 coal requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather and availability of equipment.

To operate NSP-Minnesota's nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium- and long-term contracts for uranium, conversion and enrichment with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions that may be exacerbated by the supply/demand imbalance.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2008, approximately 63 percent of the requirements for 2009, 72 percent of the requirements for 2010 through 2012, 69 percent of the requirements for 2013 through 2015, 28 percent of the requirements for 2016 and 2017, with no coverage of requirements for 2018 and beyond. Contracts with additional uranium concentrate suppliers are currently in various stages of negotiations that are expected to provide a portion of the remaining open requirements through 2019.
- Current contracts for conversion services cover 100 percent of the requirements through 2011 and approximately 52 percent of the requirements from 2012 through 2015, with no coverage for 2016 and beyond.

- Current enrichment services contracts cover 100 percent of 2008 and approximately 94 percent of 2009 requirements. Approximately 29 percent of the 2010 through 2013 enrichment services requirements are currently covered with no coverage of requirements for 2014 and beyond. These current contracts expire at varying times between 2009 and 2013. A contract for additional enrichment services is being negotiated to provide 100 percent coverage for 2009 through 2013.
- The fuel fabrication contract for Monticello was extended during 2007 to cover one additional reload in 2011. Prairie Island's fuel fabrication is 100 percent committed for six reloads with an option to extend for three additional reloads. The six reloads provide for fabrication services through at least 2013, while adding the optional reloads would provide for fabrication services to at least 2015. Request for proposals from the fuel fabrication vendors for additional supply for Monticello is planned for 2008 with contract negotiations to follow.

NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Contracts for additional uranium are currently being negotiated that would provide additional supply requirements through 2019. Some exposure to price volatility will remain, due to index-based pricing structures on the contracts.

The NSP System uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for power plants are procured under contracts with various terms to provide an adequate supply of fuel. The NSP System presently has no long-term supply commitments. The transportation and storage contracts expire in various years from 2010 to 2028. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, NSP-Minnesota's commitments related to these transportation and storage contracts were approximately $575 million. The NSP System has limited on-site fuel oil storage facilities and relies on the spot market for incremental supplies, if needed.

## Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. NSP-Minnesota uses physical and financial instruments to reduce commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures About Market Risk.

# NSP-Wisconsin

## Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction —*** Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale and the transmission of electricity in interstate commerce. NSP-Wisconsin has received authorization from the FERC to make wholesale electric sales at market-based prices (see market-based rate authority discussion).

The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year beginning the following January.

***Fuel and Purchased Energy Cost Recovery Mechanisms —*** NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference of 2 percent above or below base rates, the PSCW may hold hearings limited to fuel costs and revise rates upward or downward. Any revised rates would remain in effect until the next rate change. The adjustment approved is calculated on an annual basis, but applied prospectively. NSP-Wisconsin's wholesale electric rate schedules include an FCA (wholesale) to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

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

***Wisconsin Renewable Portfolio Standard —*** The Wisconsin legislature passed a Renewable Portfolio Standard (RPS) that requires 10 percent of electric sales statewide be supplied by renewable energy sources by the year 2015. However, under the RPS, each individual utility must increase its renewable percentage by 6 percent over its baseline level. For NSP-Wisconsin the RPS is 12.85 percent since its baseline percentage was 6.85 percent. NSP-Wisconsin anticipates it will meet the RPS requirements with its pro-rata share of existing and planned renewable generation on the NSP System. Costs associated with complying with the standard are recoverable through general rate cases and the fuel cost recovery mechanism described above.

## Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See discussion of the system capacity and demand under NSP-Minnesota Capacity and Demand discussed previously.

## Energy Sources and Related Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See a discussion of the system energy sources under NSP-Minnesota Energy Sources and Related Initiatives discussed previously.

## Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See a discussion of the system energy sources under NSP-Minnesota Fuel Supply and Costs discussed previously.

# PSCo

## Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction* —** PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale and the transmission of electricity in interstate commerce. PSCo has received authorization from the FERC to make wholesale electricity sales at market-based prices, however, as discussed previously, PSCo withdrew its market-based rate authority with respect to sales in its own and affiliated operating company control areas.

***Fuel, Purchased Energy and Conservation Cost Recovery Mechanisms* —** PSCo has several retail adjustment clauses that recover fuel, purchased energy and other resource costs:

- *ECA* — Effective Jan. 1, 2007 the ECA includes an incentive adjustment to encourage efficient operation of base load coal plants and encourage cost reductions through purchases of economical short-term energy. The total incentive payment to PSCo in any calendar year will not exceed $11.25 million. The ECA mechanism is revised quarterly and interest accrues monthly on the average deferred balance. The ECA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010.
- *PCCA* — The PCCA allows for recovery of purchased capacity payments to power suppliers under specifically identified power purchase agreements that are not included in the determination of PSCo's base electric rates or other recovery mechanisms. Effective Jan. 1, 2007, all prudently incurred purchased capacity costs are recovered through the PCCA. The PCCA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010.
- *SCA* — The SCA allows PSCo to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised annually on Jan. 1, as well as on an interim basis to coincide with changes in fuel costs.
- *AQIR* — The AQIR recovers, over a 15-year period, the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of a voluntary plan, effective Jan. 1, 2003, to reduce emissions and improve air quality in the Denver metro area.
- *DSMCA* — The DSMCA clause permits PSCo to recover DSM costs beginning Jan. 1, 2006 over eight years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. DSM costs incurred prior to Jan. 1, 2006 are recovered over 5 years. PSCo also has a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the DSMCA.
- *Renewable Energy Service Adjustment (RESA)* — The RESA recovers costs associated with complying with the provisions of a citizen referred ballot initiative passed in 2004 that establishes a renewable portfolio standard for

PSCo's electric customers. Currently, the RESA recovers the incremental costs of compliance with the RES and is set at a level of 0.6 percent of the net costs.

- *Wind Energy Service Adjustment (WESA)* — The WESA provides for the recovery of certain costs associated with the provision of wind energy resources from those customers subscribed as WindSource renewable energy customers.
- *Transmission Cost Adjustment (TCA)* — Effective January 2008, the TCA provides for the recovery outside of rate cases of transmission plant revenue requirements and allows for a return on construction work in progress for investments for grid reliability or for new or upgraded transmission facilities.

PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause accepted for filing by the FERC.

***Performance-Based Regulation and Quality of Service Requirements* —** PSCo currently operates under an electric and natural gas PBRP. The major components of this regulatory plan include:

- 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 2010; and
- a natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service through 2010.

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. 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.

## Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2008, assuming normal weather, are listed below.

| | System Peak Demand (in MW) | | | |
|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 Forecast |
| PSCo | 6,975 | 6,757 | 6,950 | 6,877 |

The peak demand for PSCo's system typically occurs in the summer. The 2007 system peak demand for PSCo occurred on July 24, 2007.

## Energy Sources and Related Transmission Initiatives

PSCo expects to meet its system capacity requirements through existing electric generating stations, power purchases, new generation facilities, DSM options and phased expansion of existing generation at select power plants.

***Purchased Transmission Services* —** In addition to using its own transmission system, PSCo has contractual arrangements with regional transmission service providers to deliver power and energy to PSCo's native load customers, which are retail and wholesale load obligations with terms of more than one year.

***Purchased Power* —** PSCo has contractual arrangements to purchase power from other utilities and independent power producers. Capacity is the measure of the rate at which a particular generating source produces electricity. Energy is a measure of the amount of electricity produced from a particular generating source over a period of time. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

PSCo also makes short-term purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to comply with minimum availability requirements, to obtain energy at a lower cost than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

***PSCo Resource Plan* —** PSCo estimates it will purchase approximately 40 percent of its total electric system energy needs for 2008 and generate the remainder with PSCo-owned resources. Additional capacity has been secured under contract making additional energy available for purchase, if required. PSCo currently has under contract or through owned generation, the resources necessary to meet its anticipated 2008 load obligation. In November 2007, PSCo filed the Colorado Resource Plan (CRP), which details the type and amount of resources that will be added to the system for an eight year Resource Acquisition Period (RAP) through 2015. Based on the plan, PSCo would:

- Increase wind power resources by 800 MW by 2015. PSCo would then have a total of approximately 1,900 MW of wind power resources.
- Acquire approximately 25 MW from a central solar facility, with plans to bring in a plant of up to 200 MW as technology develops.
- Pursue an additional 29 MW of on-site, customer-owned solar installations.
- Increase customer efficiency and conservation programs with plans to double the current capacity of its programs to 694 MW, while tripling the amount of annual energy sales reductions to approximately 2,350 GWh, by 2020.
- Retire two older coal-burning plants (Arapahoe and Cameo) and repower at the Arapahoe site with a 480 MW summer rated combined cycle plant.

Also in November 2007, PSCo terminated a purchased power agreement, purchased the assets of the Squirrel Creek LLC project and filed a Certificate of Public Convenience and Necessity application with the CPUC to use the combustion turbines to build a new, company owned project at the existing Ft. St. Vrain generating station. This facility would come on line in 2009. If approved by the CPUC, the Fort St. Vrain project will leave PSCo 119 MW short of the necessary peaking power and 16 percent short of reserve margin necessary to meet the 2009 summer peak load. PSCo will meet the differential for the summer 2009 peak by purchasing short-term capacity. PSCo is requesting CPUC approval of the Fort St. Vrain application by April 2008.

Construction continues on a plant approved in the last resource planning docket (2003) of a 750 MW pulverized coal-fired unit at the existing Comanche power station located near Pueblo, Colo. and installation of additional emission control equipment on the two existing Comanche station units.

PSCo began construction of the new facility in the fall of 2005. Completion is planned for the fall of 2009. As part of an electric rate case, PSCo is allowed to include construction work in progress associated with the Comanche 3 project in rate base without an offset for allowance for funds used during construction, depending upon PSCo's senior unsecured debt rating.

PSCo has an agreement with Intermountain Rural Electric Association (IREA) and Holy Cross which transfers a portion of capacity ownership in the Comanche 3 unit to IREA and Holy Cross.

***Renewable Energy Standard* —** The 2007 Colorado legislature adopted an increased RES that requires PSCo to generate or cause to be generated electricity from renewable resources equaling:

- At least 10 percent of its retail sales by 2010,
- 15 percent of retail sales by 2015 and
- 20 percent of retail sales by 2020.
- The new law limits the incremental retail rate impact from these acquisitions to 2 percent. The new legislation encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a rider mechanism and a return on construction work in progress.

***Colorado Climate Action Plan* —** In November 2007, Governor Ritter of Colorado published a Colorado Climate Action Plan, which calls for a reduction in GHG emissions of 20 percent by 2020 with additional reductions by 2050.

***RESA* —** In March 2006, the CPUC approved a RESA rider of 0.6 percent. The revenues collected under the RESA will be used to acquire sufficient solar resources to meet the on-site solar system requirements in the Colorado statutes. In response to the new RES, PSCo filed in late 2007 to increase the RESA to a full 2 percent in order to increase renewables to levels that comply with the 20 percent renewable energy requirement.

***TCR Legislation* —** In 2007, a law was passed in Colorado which provides for rate rider recovery of all costs a utility incurs in the planning, development and construction or expansion of transmission facilities and for current recovery through this rider of the utility's weighted average cost of capital on transmission construction work in progress as of the end of the prior year. This legislation also provides for rate-regulated Colorado utilities to develop plans to construct or expand transmission facilities to transmission constrained zones where new electric generation facilities, including renewable energy facilities, are likely to be located and provides for expedited approvals for such facilities.

In October 2007, PSCo filed an application under the new legislation for a Certificate of Public Convenience and Necessity to construct a 345 KV transmission line from Pawnee Substation to its Smoky Hill Substation. The proposed new transmission line is intended to allow for injection of new generation capacity at Pawnee Substation for delivery to

PSCo's load center located on the front range. PSCo estimates the cost of the new line to be approximately $110 million over five years.

## Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

| | Coal | | Natural Gas | | Average Fuel |
|---|---|---|---|---|---|
| | Cost | Percent | Cost | Percent | Cost |
| 2007 | $1.26 | 84% | $4.34 | 16% | $1.76 |
| 2006 | 1.24 | 85 | 6.52 | 15 | 2.01 |
| 2005 | 1.01 | 85 | 7.56 | 15 | 2.00 |

See additional discussion of fuel supply and costs under Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis under Item 7.

*Fuel Sources* — PSCo normally maintains approximately 30 days of coal inventory at each plant site. Coal inventory levels, however, may vary widely among plants. Coal supply inventories at Dec. 31, 2007, were approximately 41 days usage, based on the maximum burn rate for all of PSCo's coal-fired plants. PSCo's generation stations use low-sulfur western coal purchased primarily under long-term contracts with suppliers operating in Colorado and Wyoming. During 2007, PSCo's coal requirements for existing plants were approximately 10 million tons.

PSCo has contracted for coal suppliers to supply approximately 100 percent of its coal requirements in 2008, 76 percent of its coal requirements in 2009 and 30 percent of its coal requirements in 2010. Any remaining requirements will be filled through an RFP process according to the fuel supply operations procurement strategy.

PSCo has coal transportation contracts that provide for delivery for approximately 100 percent of 2008 coal requirements, 35 percent of 2009 coal requirements and 33 percent of 2010 coal requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather, and availability of equipment.

PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for associated transportation and storage services for PSCo's power plants are procured under contracts with various terms to provide an adequate supply of fuel. The supply contracts expire in various years from 2008 to 2010. The transportation and storage contracts expire in various years from 2009 to 2040. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, PSCo's commitments related to supply contracts were approximately $161 million and transportation and storage contracts were approximately $1.0 billion.

## Wholesale Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. PSCo uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A — Quantitative and Qualitative Disclosures About Market Risk.

# SPS

## Public Utility Regulation

*Summary of Regulatory Agencies and Areas of Jurisdiction* — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have jurisdiction over SPS' rates in those communities. The NMPRC also has jurisdiction over the issuance of securities. SPS is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale and the transmission of electricity in interstate commerce. SPS has received authorization from the FERC to make wholesale electricity sales at market-based prices, however, as discussed previously, SPS withdrew its market-based rate authority with respect to sales in its own and affiliated operating company control areas.

*Fuel, Purchased Energy and Conservation Cost Recovery Mechanisms* — Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric rates. The Texas retail fuel factors change each November and May based on the projected cost of natural gas.

If it appears that SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the PUCT. The regulations require refunding or surcharging over- or under-recovery amounts, including interest, when they exceed 4 percent of the utility's annual fuel and purchased energy costs, if this condition is expected to continue. SPS is participating in a PUCT rulemaking project to amend the PUCT's regulations to provide for more frequent timely changes in fixed fuel factors.

PUCT regulations require periodic examination of SPS fuel and purchased energy costs, the efficiency of the use of fuel and purchased energy, fuel acquisition and management policies and purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review at least every three years the operations of SPS' electric generation and fuel management activities as it relates to fuel and purchased energy costs.

The NMPRC regulations provide for a fuel and purchased power cost adjustment clause for SPS' New Mexico retail jurisdiction. SPS files monthly and annual reports of its fuel and purchased power costs with the NMPRC. The NMPRC authorized SPS to implement a monthly adjustment factor.

SPS recovers fuel and purchased energy costs from its wholesale customers through a wholesale fuel and purchased economic energy cost adjustment clause (FCAC) accepted for filing by the FERC.

*Performance-Based Regulation and Quality of Service Requirements* — In Texas, SPS is subject to a quality of service plan requiring SPS to comply with electric service reliability performance targets. If these targets are not met, the PUCT staff may initiate proceedings for an investigation and possible imposition of an administrative penalty.

*Texas Energy Legislation* — The 2005 Texas legislature passed a law, effective June 18, 2005, establishing statutory authority for electric utilities outside of the ERCOT in the SPP or the WECC to have timely recovery from Texas retail consumers of utility transmission infrastructure investments. In December 2007, the PUCT adopted regulations that allow such utilities, including SPS, to seek approval of a TCR factor for recovery on an annual basis of the reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges under a tariff approved by the FERC.

*Texas Renewable Energy Zones* — In 2007, the PUCT designated competitive renewable energy zones (CREZs), which are regions of the state which are sufficient to develop renewable energy generation sources, such as wind. Several CREZ areas within the SPS service region were designated for potential development. A statewide study conducted by the ERCOT identifies the Texas panhandle as having the top four of the state's primary areas for wind energy expansion. Several transmission proposals have been filed in the CREZ proceeding, including plans to interconnect CREZs with the SPP and plans that would collect wind energy from panhandle CREZs and deliver it into ERCOT.

*Texas Goal for Renewable Energy* — The Texas legislature and the PUCT have adopted renewable portfolio standards that require the development of renewable resources by 2007 and increasing requirements through 2025. SPS has already solicited for renewable energy resources and they have been developed in the SPS area and are providing renewable energy sufficient to meet the Texas renewable energy requirements.

*John Deere Wind Complaint* — On June 27, 2007, several of the John Deere wind subsidiaries (JD Wind) filed a complaint against SPS disputing SPS' payments to JD Wind for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind for energy produced from its QF is appropriate and in accordance with SPS' filed tariffs with the PUCT. The PUCT has referred the complaint to the State Office of Administrative Hearings.

*New Mexico Renewable Portfolio Standard* — The 2007 New Mexico legislature enacted a renewable portfolio standard in which renewable energy must comprise no less than 5 percent of retail sales by 2006; 10 percent by 2011; 15 percent by 2015; and 20 percent by 2020. The legislation also allows incentives to encourage the acquisition of renewable energy supplies beyond the requirements. The NMPRC has implemented revised rules related to the increased requirements. The NMPRC has interpreted the diversification requirement to mean no less than 20 percent of the standard is met using wind energy, no less than 20 percent using central solar, no less than 10 percent other (e.g., biomass, geothermal), and no less than 1.5 percent using renewable distributed generation (increasing to 3 percent by 2015). The effective date of the diversification requirements is 2011.

## Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2008, assuming normal weather, are listed below.

| | System Peak Demand (in MW) | | | |
|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 Forecast |
| SPS | 4,660 | 4,711 | 4,731 | 4,908 |

The peak demand for the SPS system typically occurs in the summer. The 2007 system peak demand for SPS occurred on Aug. 20, 2007.

## Energy Sources and Related Transmission Initiatives

SPS expects to use existing electric generating stations, power purchases and DSM options to meet its net dependable system capacity requirements.

***Purchased Power —*** SPS has contractual arrangements to purchase power from other utilities and independent power producers. Capacity is the measure of the rate at which a particular generating source produces electricity. Energy is a measure of the amount of electricity produced from a particular generating source over a period of time. Long-term purchase power contracts typically require a periodic payment to secure the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

SPS also makes short-term purchases to replace generation from company-owned units that are unavailable due to maintenance and unplanned outages, to comply with minimum availability requirements, to obtain energy at a lower cost than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

### *SPS Resource Planning*

*Lea Power Partners* — Lea Power is a natural gas combined cycle 602 MW plant currently being constructed near Hobbs, New Mexico. SPS is expected to begin to take energy beginning June 2008 when Lea Power reaches commercial operations. The purchase power agreement, which was executed in 2006, provides for SPS to have exclusive rights to dispatch the facility.

*Integrated Resource Planning* — In accordance with a final rule adopted by the NMPRC, SPS is required to file an integrated resource plan (IRP) with the NMPRC on or before July 2009. Also as part of this requirement, SPS must initiate a public advisory process on or before July 2008.

*Acquisition of Renewable Resources* — In accordance with a final rule adopted by the NMPRC, SPS must require certain quantities and specific types of renewable resources on or before 2011. To meet this requirement, SPS plans to submit an RFP during the first quarter of 2008. See discussion above on New Mexico Renewable Portfolio Standard.

***Purchased Transmission Services —*** SPS has contractual arrangements with SPP and regional transmission service providers to deliver power and energy to its native load customers, which are retail and wholesale load obligations with terms of more than one year.

All of the transmission arrangements for the SPS systems are through FERC approved OATT. SPS also has several transmission arrangements through the SPP OATT. The SPP is a RTO that, among other things, administers an OATT for all its members. SPS' entire service territory is within the SPP footprint, and SPS is a member of the SPP. The SPP owns no transmission facilities. Rather, the SPP is responsible for ensuring that transmission service across facilities owned by others, including SPS, is made available and used on a reliable and non-discriminatory basis. These OATTs contain policies and procedures for reliable use of the transmission systems for transmission, generation and load variations.

## Fuel Supply and Costs

The following table shows the delivered cost per MMBtu of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels.

| | Coal | | Natural Gas | | Average Fuel |
|---|---|---|---|---|---|
| SPS Generating Plants | Cost | Percent | Cost | Percent | Cost |
| 2007 | $1.64 | 67% | $6.45 | 33% | $3.22 |
| 2006 | 1.89 | 66 | 6.30 | 34 | 3.38 |
| 2005 | 1.32 | 68 | 7.77 | 32 | 3.38 |

See additional discussion of fuel supply and costs under Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis under Item 7.

***Fuel Sources —*** SPS purchases all of its coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO, Inc (TUCO). TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to the plant bunkers to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters, and handlers.

- For the Harrington station, the coal supply contract with TUCO expires in 2016.
- For the Tolk station, the coal supply contract with TUCO expires in 2017.
- As of Dec. 31, 2007, coal supplies at the Harrington and Tolk sites were approximately 34 and 31 days supply, respectively.
- TUCO has coal agreements to supply 100 percent of SPS' coal requirements in 2008 and 2009, and 82 percent of the 2010 coal requirements, which are sufficient quantities to meet the primary needs of the Harrington and Tolk stations.

SPS uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for SPS' power plants are procured under contracts with various terms to provide an adequate supply of fuel. The supply contracts expire in various years from 2008 through 2010. The transportation and storage contracts expire in various years from 2008 to 2033. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, SPS' commitments related to supply contracts were approximately $31 million and transportation and storage contracts were approximately $254 million.

## Wholesale Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. See additional discussion under Item 7A—Quantitative and Qualitative Disclosures About Market Risk.

# Xcel Energy Electric Operating Statistics

| | Year Ended Dec. 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Electric Sales (Millions of Kwh)** | | | |
| Residential | 24,866 | 24,153 | 23,930 |
| Commercial and Industrial | 62,396 | 61,314 | 60,049 |
| Public Authorities and Other | 1,087 | 1,118 | 1,091 |
| **Total Retail** | 88,349 | 86,585 | 85,070 |
| Sales for Resale | 24,202 | 23,960 | 22,194 |
| **Total Energy Sold** | 112,551 | 110,545 | 107,264 |
| **Number of Customers at End of Period** | | | |
| Residential | 2,859,262 | 2,831,704 | 2,791,859 |
| Commercial and Industrial | 408,366 | 403,678 | 400,035 |
| Public Authorities and Other | 71,726 | 73,279 | 75,937 |
| **Total Retail** | 3,339,354 | 3,308,661 | 3,267,831 |
| Wholesale | 129 | 138 | 128 |
| **Total Customers** | 3,339,483 | 3,308,799 | 3,267,959 |
| **Electric Revenues (Thousands of Dollars)** | | | |
| Residential | $2,281,354 | $2,149,978 | $2,048,100 |
| Commercial and Industrial | 4,099,017 | 4,014,809 | 3,733,648 |
| Public Authorities and Other | 118,024 | 118,660 | 110,895 |
| **Total Retail** | 6,498,395 | 6,283,447 | 5,892,643 |
| Wholesale | 1,180,728 | 1,141,248 | 1,193,762 |
| Other Electric Revenues | 168,869 | 183,323 | 157,232 |
| **Total Electric Revenues** | $7,847,992 | $7,608,018 | $7,243,637 |
| Kwh Sales per Retail Customer | 26,457 | 26,169 | 26,033 |
| Revenue per Retail Customer | $ 1,946.00 | $ 1,899.09 | $ 1,803.23 |
| Residential Revenue per Kwh | 9.17¢ | 8.90¢ | 8.56¢ |
| Commercial and Industrial Revenue per Kwh | 6.57 | 6.55 | 6.22 |
| Wholesale Revenue per Kwh | 4.88 | 4.76 | 5.38 |

# NATURAL GAS UTILITY OPERATIONS

## Natural Gas Utility Trends

The most significant recent developments in the natural gas operations of the utility subsidiaries are continued volatility in wholesale natural gas market prices and the continued trend toward declining use per customer by residential customers as a result of improved building construction technologies and higher appliance efficiencies. From 1997 to 2007, average annual sales to the typical residential customer declined from 102 MMBtu per year to 82 MMBtu per year on a weather-normalized basis. Although recent wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, the high prices are expected to encourage further efficiency efforts by customers.

## NSP-Minnesota

### Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction —*** Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over aspects of NSP-Minnesota's financial activities, including security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting customers' future energy needs.

***Purchased Gas and Conservation Cost Recovery Mechanisms —*** NSP-Minnesota's retail natural gas rates for Minnesota and North Dakota include a PGA clause that provides for prospective monthly rate adjustments to reflect the forecasted cost of purchased natural gas. The annual difference between the natural gas costs collected through PGA rates and the actual natural gas costs are collected or refunded over the subsequent 12-month period. The MPUC and NDPSC have the authority to disallow recovery of certain costs if they find the utility was not prudent in its procurement activities.

NSP-Minnesota is required by Minnesota law to spend a minimum of 0.5 percent of Minnesota natural gas revenue on conservation improvement programs. These costs are recovered through an annual cost recovery mechanism for natural gas conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually. While this law will change to a savings-based requirement beginning in 2010 pursuant to 2007 legislation, the costs of providing qualified conservation improvement programs will continue to be recoverable through a rate adjustment mechanism.

### Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 643,320 MMBtu for 2007, which occurred on Feb. 7, 2007.

NSP-Minnesota purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 562,298 MMBtu/day. In addition, NSP-Minnesota has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 30 percent of winter natural gas requirements and 36 percent of peak day, firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.13 Bcf equivalent and three propane-air plants with a storage capacity of 1.4 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 250,300 MMBtu of natural gas per day, or approximately 33 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. The 2006-2007 and 2007-2008 entitlement levels are pending MPUC action.

### Natural Gas Supply and Costs

NSP-Minnesota actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, NSP-Minnesota conducts natural gas price hedging activity that has been approved by the MPUC. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Minnesota's regulated retail natural gas distribution business:

| | |
|---|---|
| 2007 | $7.67 |
| 2006 | 8.32 |
| 2005 | 8.90 |

The cost of natural gas supply, transportation service and storage service is recovered through the PGA cost recovery mechanism.

NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2008 through 2027.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, NSP-Minnesota was committed to approximately $813 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 25 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis under Item 7.

## NSP-Wisconsin

### Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction* —** NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. The filing procedure and review generally allow the PSCW sufficient time to issue an order and implement new base rates effective with the start of the test year.

***Natural Gas Cost Recovery Mechanisms* —** NSP-Wisconsin has a retail PGA cost recovery mechanism for Wisconsin operations to recover changes in the actual cost of natural gas and transportation and storage services. The PSCW has the authority to disallow certain costs if it finds the utility was not prudent in its procurement activities.

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

### Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 173,617 MMBtu for 2007, which occurred on Feb. 4, 2007.

NSP-Wisconsin purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 129,511 MMBtu/day. In addition, NSP-Wisconsin has contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 26 percent of winter natural gas requirements and 40 percent of peak day, firm requirements of NSP-Wisconsin.

NSP-Wisconsin also owns and operates one LNG plant with a storage capacity of 270,000 Mcf equivalent and one propane-air plant with a storage capacity of 2,700 Mcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 18,408 MMBtu of natural gas per day, or approximately 13 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2007-2008 supply plan was approved by the PSCW in November 2007.

## Natural Gas Supply and Costs

NSP-Wisconsin actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, NSP-Wisconsin conducts natural gas price hedging activity that has been approved by the PSCW. This diversification involves numerous domestic and Canadian supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by NSP-Wisconsin's regulated retail natural gas distribution business:

| | |
|---|---|
| 2007 | $7.56 |
| 2006 | 8.42 |
| 2005 | 8.64 |

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

NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2008 through 2027.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, NSP-Wisconsin was committed to approximately $80 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing short-term agreements from approximately 25 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis under Item 7.

# PSCo

## Public Utility Regulation

***Summary of Regulatory Agencies and Areas of Jurisdiction*** — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction under the federal Natural Gas Act.

***Purchased Gas and Conservation Cost Recovery Mechanisms*** — PSCo has two retail adjustment clauses that recover purchased gas and other resource costs:

- *GCA* — The GCA mechanism allows PSCo to recover its actual costs of purchased gas, including costs for upstream pipeline services PSCo incurs to meet the requirements of its local distribution system customers. The GCA is revised monthly to allow for changes in gas rates.
- *DSMCA* — PSCo has a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the gas DSMCA.

***Performance-Based Regulation and Quality of Service Requirements*** — The CPUC established a combined electric and natural gas quality of service plan. See further discussion under Item 1, Electric Utility Operations.

## Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation, which include transportation customers contracting for firm supply backup, to be 1,864,044 MMBtu. In addition, firm transportation customers hold 591,140 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,455,184 MMBtu per day. The maximum daily deliveries for PSCo in 2007 for firm and interruptible services were 1,798,030 MMBtu on Jan. 12, 2007.

PSCo purchases natural gas from independent suppliers. These purchases are generally priced based on market indices that reflect current prices. The natural gas is delivered under natural gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,612,234 MMBtu/day, which includes 831,866 MMBtu of supplies held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide about 35,000 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo's city gate meter stations and a small amount is received directly from wellhead sources.

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

## Natural Gas Supply and Costs

PSCo actively seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. In addition, PSCo conducts natural gas price hedging activities that have been approved by the CPUC. This diversification involves numerous supply sources with varied contract lengths.

The following table summarizes the average delivered cost per MMBtu of natural gas purchased for resale by PSCo's regulated retail natural gas distribution business:

| | |
|---|---|
| 2007 | $5.87 |
| 2006 | 7.09 |
| 2005 | 8.01 |

PSCo has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2007, PSCo was committed to approximately $1.9 billion in such obligations under these contracts, which expire in various years from 2008 through 2028.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2007, PSCo purchased natural gas from approximately 40 suppliers.

See additional discussion of natural gas costs under Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis under Item 7.

## Xcel Energy Gas Operating Statistics

| | Year Ended Dec. 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Gas Deliveries (Thousands of MMBtu)** | | | |
| Residential | 138,198 | 126,846 | 135,794 |
| Commercial and Industrial | 88,668 | 81,107 | 83,667 |
| **Total Retail** | 226,866 | 207,953 | 219,461 |
| Transportation and Other | 133,851 | 135,708 | 134,061 |
| **Total Deliveries** | 360,717 | 343,661 | 353,522 |
| **Number of Customers at End of Period** | | | |
| Residential | 1,688,994 | 1,669,747 | 1,636,652 |
| Commercial and Industrial | 149,557 | 147,614 | 145,067 |
| **Total Retail** | 1,838,551 | 1,817,361 | 1,781,719 |
| Transportation and Other | 4,146 | 3,981 | 3,764 |
| **Total Customers** | 1,842,697 | 1,821,342 | 1,785,483 |
| **Gas Revenues (Thousands of Dollars)** | | | |
| Residential | $1,295,095 | $1,330,025 | $1,450,316 |
| Commercial and Industrial | 738,035 | 755,204 | 794,230 |
| **Total Retail** | 2,033,130 | 2,085,229 | 2,244,546 |
| Transportation and Other | 78,602 | 70,770 | 62,839 |
| **Total Gas Revenues** | $2,111,732 | $2,155,999 | $2,307,385 |
| MMBtu Sales per Retail Customer | 123.39 | 114.43 | 123.17 |
| Revenue per Retail Customer | $ 1,105.83 | $ 1,147.39 | $ 1,259.76 |
| Residential Revenue per MMBtu | 9.37 | 10.49 | 10.68 |
| Commercial and Industrial Revenue per MMBtu | 8.32 | 9.31 | 9.49 |
| Transportation and Other Revenue per MMBtu | 0.59 | 0.52 | 0.47 |

## ENVIRONMENTAL MATTERS

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

Xcel Energy and its subsidiaries strive to comply with all environmental regulations applicable to its operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have upon Xcel Energy's operations. For more information on environmental contingencies, see Notes 15 and 16 to the consolidated financial statements, environmental matters in Management's Discussion and Analysis under Item 7 and the matters discussed below.

***Leyden Natural Gas Storage Facility (Leyden)* —** In February 2001, the CPUC approved PSCo's plan to abandon Leyden after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. The final report of post closure monitoring will be filed with the Colorado Oil and Gas Conservation Commission in early 2008. As of Dec. 31, 2005, PSCo had incurred approximately $5.7 million of costs associated with engineering buffer studies, damage claims paid to landowners and other initial closure costs. PSCo accrued an additional $0.2 million of costs through 2006 to complete the decommissioning and closure of the facility. In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional Leyden costs, plus unrecovered amounts authorized from a previous rate case, which amounted to $5.9 million to be amortized over four years. The total amount PSCo requested to be recovered from customers was $7.7 million. Xcel Energy reached a settlement agreement with the parties in the 2006 rate case accepting the PSCo recovery amounts. The CPUC approved the settlement agreement in June 2007.

## CAPITAL SPENDING AND FINANCING

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

## EMPLOYEES

The number of full-time Xcel Energy employees in continuing operations at Dec. 31, 2007, is presented in the table below. Of the full-time employees listed below, 5,663, or 52 percent, are covered under collective bargaining agreements. See Note 10 in the consolidated financial statements for further discussion of the bargaining agreements.

| | |
|---|---|
| NSP-Minnesota | 3,561 |
| NSP-Wisconsin | 543 |
| PSCo | 2,734 |
| SPS | 1,145 |
| Xcel Energy Services Inc | 2,934 |
| Total | 10,917 |

## EXECUTIVE OFFICERS

Richard C. Kelly, 61, Chairman of the Board, Xcel Energy Inc., December 2005 to present; Chief Executive Officer, Xcel Energy Inc., July 2005 to present; President, Xcel Energy Inc., October 2003 to present. Previously, Chief Operating Officer, Xcel Energy Inc., October 2003 to June 2005, Vice President and Chief Financial Officer, Xcel Energy Inc., August 2002 to October 2003 and President — Enterprises Business Unit, Xcel Energy, August 2000 to August 2002.

Paul J. Bonavia, 56, President — Utilities Group, Xcel Energy Inc., November 2005 to present; Vice President, Xcel Energy Services Inc., September 2000 to present. Previously, President — Commercial Enterprises Business Unit, Xcel Energy, December 2003 to October 2005 and President — Energy Markets Business Unit, Xcel Energy, August 2000 to December 2003.

Michael C. Connelly, 46, Vice President and General Counsel, Xcel Energy Inc., June 2007 to present. Previously, Vice President of Human Resources November 2005 to June 2007; Vice President and Deputy General Counsel January 2003 to November 2005; Deputy General Counsel August 2000 to January 2003.

David L. Eves 49, President and Director, SPS, December 2006 to present; Chief Executive Officer, SPS, August 2006 to present. Previously, Vice President of Resource Planning and Acquisition, Xcel Energy, November 2002 to July 2006 and Managing Director, Resource Planning and Acquisition, Xcel Energy, August 2000 to November 2002.

Benjamin G.S. Fowke III, 49, Chief Financial Officer, Xcel Energy Inc., October 2003 to present; Vice President, Xcel Energy Inc., November 2002 to present. Previously, Treasurer, Xcel Energy Inc., November 2002 to May 2004 and Vice President and Chief Financial Officer — Energy Markets Business Unit, Xcel Energy, August 2000 to November 2002.

Raymond E. Gogel, 57, Vice President, Xcel Energy Services Inc., April 2002 to present; Vice President Customer and Enterprise Solutions and Chief Administrative Officer, November 2005 to present. Previously, Chief Information Officer, Xcel Energy Services Inc., April 2002 to February 2006; Vice President and Senior Client Services Principal, IBM Global Services, April 2001 to April 2002 and Senior Project Executive, IBM Global Services, April 1999 to April 2001.

Cathy J. Hart, 58, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present; Vice President, Corporate Services Group, November 2005 to present.

Cynthia L. Lesher, 59, President of the Minnesota host committee for the Republican National Convention as a loaned executive to the convention organization, January 2007 to present. President and Chief Executive Officer, NSP-Minnesota, October 2005 to present. Previously, Chief Administrative Officer, Xcel Energy, August 2000 to October 2005 and Chief Human Resources Officer, Xcel Energy, July 2001 to October 2005.

Teresa S. Madden, 51, Vice President and Controller, Xcel Energy Inc., January 2004 to present. Previously, Vice President of Finance — Customer and Field Operations Business Unit, Xcel Energy, August 2003 to January 2004, Interim CFO, Rogue Wave Software, Inc., February 2003 to July 2003 and Corporate Controller, Rogue Wave Software, Inc., October 2000 to February 2003.

David M. Sparby, 53, Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to present; Previously, Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

Michael L. Swenson, 57, President, Director and Chief Executive Officer, NSP-Wisconsin, February 2002 to present. Previously, State Vice President for North Dakota and South Dakota, August 2000 to February 2002.

Tim E. Taylor, 60, President, Director and Chief Executive Officer, Public Service Company of Colorado, September 2007 to present. Previously, Vice President of Asset Management — Utilities Group, Xcel Energy, Inc., February 2006 to September 2007; Vice President, Field Operations, January 2004 to February 2006 and Vice President, Asset Management, May 2002 to January 2004.

George E. Tyson II, 42, Vice President and Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy, July 2003 to May 2004; Director of Origination — Energy Markets Business Unit, Xcel Energy, May 2002 to July 2003; Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

David M. Wilks, 61, Vice President, Xcel Energy Services Inc., September 2000 to present; President — Energy Supply Group, Xcel Energy Inc., August 2000 to present.

No family relationships exist between any of the executive officers or directors.

# Item 1A — Risk Factors

## Risks Associated with Our Business

***Our profitability depends in part on the ability of our utility subsidiaries to recover their costs from their customers and there may be changes in circumstances or in the regulatory environment that impair the ability of our utility subsidiaries to recover costs from their customers.***

We are subject to comprehensive regulation by federal and state utility regulatory agencies. The utility commissions in the states where our utility subsidiaries operate regulate many aspects of our utility operations, including siting and construction of facilities, customer service and the rates that we can charge customers. The FERC has jurisdiction, among other things, over wholesale rates for electric transmission service and the sale of electric energy in interstate commerce.

The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services to our customers. Our utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the utility's expenses incurred in a test year. Our utility subsidiaries are subject to both future and historical test years depending upon the regulatory mechanisms approved in each jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its expenses at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commission will judge all the costs of our utility subsidiaries to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of such costs. Rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Furthermore, there could be changes in the regulatory environment that would impair the ability of our utility subsidiaries to recover costs historically collected from their customers. If all of the costs of our utility subsidiaries are not recovered through customer rates, they could incur financial operating losses, which, over the long term, could jeopardize their ability to pay us dividends and our ability to meet our financial obligations.

Management currently believes these prudently incurred costs are recoverable given the existing regulatory mechanisms in place. However, changes in regulations or the imposition of additional regulations, including additional environmental regulation or regulation related to climate change, could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including paying dividends on our common stock.

***Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.***

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. For example, Standard and Poor's calculates an imputed debt associated with capacity payments from purchase power contracts. An increase in the overall level of capacity payments would increase the amount of imputed debt, based on Standard and Poor's methodology. Therefore, Xcel Energy and its subsidiaries credit ratings could be adversely affected based on the level of capacity payments associated with purchase power contracts or changes in how imputed debt is determined. Any downgrade could lead to higher borrowing costs.

***We are subject to interest rate risk.***

If interest rates increase, we may incur increased interest expense on variable interest debt or short-term borrowings, which could have an adverse impact on our operating results.

***We are subject to capital market risk.***

Utility operations require significant capital investment in plant, property and equipment; consequently, Xcel Energy is an active participant in debt and equity markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous events throughout the world economy. Capital market disruption events, as evidenced by the collapse in the U.S. sub-prime mortgage market, could prevent Xcel Energy from issuing new securities or cause us to issue securities with less than ideal terms and conditions.

***We are subject to credit risks.***

Credit risk includes the risk that counterparties that owe us money or product will breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

***We are subject to commodity risks and other risks associated with energy markets.***

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products and are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting), which may cause earnings volatility. We utilize quoted observable market prices to the maximum extent possible in determining the value of these derivative commodity instruments. For positions for which observable market prices are not available, we utilize observable quoted market prices of similar assets or liabilities or indirectly observable prices based on forward price curves of similar markets. For positions for which we have unobservable market prices, we incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions and significant changes from our assumptions could cause significant earnings variability.

If we encounter market supply shortages, we may be unable to fulfill contractual obligations to our retail, wholesale and other customers at previously authorized or anticipated costs. Any such supply shortages could cause us to seek alternative supply services at potentially higher costs or suffer increased liability for unfulfilled contractual obligations. Any significantly higher energy or fuel costs relative to corresponding sales commitments would have a negative impact on our cash flows and could potentially result in economic losses. Potential market supply shortages may not be fully resolved through alternative supply sources and such interruptions may cause short-term disruptions in our ability to provide electric and/or natural gas services to our customers. These cost and reliability issues vary in magnitude for each operating subsidiary depending upon unique operating conditions such as generation fuels mix, availability of fuel transportation, electric generation capacity, and transmission, etc.

***We are subject to environmental laws and regulations, compliance with which could be difficult and costly.***

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, to install pollution control equipment at our facilities, clean up spills and correct environmental hazards and other contamination. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e. clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2007, these included:

- sites of former manufactured gas plants operated by our subsidiaries or predecessors; and
- third party sites, such as landfills, to which we are alleged to be a potentially responsible party that sent hazardous materials and wastes.

We are also subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. These mandates are designed in part to mitigate the potential environmental impacts of utility operations. Failure to meet the requirements of these mandates may result in fines or penalties, which could have a material adverse effect on our results of operations. If our regulators do not allow us to recover all or a part of the cost of capital investment or the operating and maintenance costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

In addition, existing environmental laws or regulations may be revised, new laws or regulations seeking to protect the environment may be adopted or become applicable to us and we may incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

*We are subject to physical and financial risks associated with climate change.*

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. Xcel Energy does not serve any coastal communities so the possibility of sea level rises does not directly affect Xcel Energy or its customers. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in more generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of the company's service territory could also have an impact on Xcel Energy revenues. Xcel Energy buys and sells electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers. Severe weather impacts Xcel Energy service territories, primarily through thunderstorms, tornadoes and snow or ice storms. We include storm restoration in our budgeting process as a normal business expense and we anticipate continuing to do so. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact Xcel Energy revenues. Xcel Energy's financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as a tax on GHGs or additional environmental regulation, would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause Xcel Energy to receive less than ideal terms and conditions.

*We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly.*

Legislative and regulatory responses related to climate change create financial risk. Increased public awareness and concern may result in more regional and/or federal requirements to reduce or mitigate the effects of GHG. Numerous states have announced or adopted programs to stabilize and reduce GHG and federal legislation has been introduced in both houses of Congress. Xcel Energy's electric generating facilities are likely to be subject to regulation under climate change policies introduced at either the state or federal level within the next few years. Xcel Energy is advocating with state and federal policy makers to design climate change regulation that is effective, flexible, low-cost and consistent with the our environmental leadership strategy.

Many of the federal and state climate change legislative proposals use a "cap and trade" policy structure, in which GHG emissions from a broad cross-section of the economy would be subject to an overall cap. Under the proposals, the cap becomes more stringent with the passage of time. The proposals establish mechanisms for GHG sources, such as power plants, to obtain "allowances" or permits to emit GHGs during the course of a year. The sources may use the allowances to cover their own emissions or sell them to other sources that do not hold enough emissions for their own operations. Proponents of the cap and trade policy believe it will result in the most cost effective, flexible emission reductions. The impact of legislation and regulations, including a "cap and trade" structure, on Xcel Energy and its customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. An important factor is Xcel Energy's ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not recover all costs related to complying with regulatory requirements imposed on Xcel Energy or its operating subsidiaries. If our regulators do not allow us to recover all or a part of the cost of capital investment or the operating and maintenance costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

For further discussion see the Management's Discussion and Analysis section and Note 15 to the consolidated financial statements.

***Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.***

NSP-Minnesota's two nuclear stations, Prairie Island and Monticello, subject it to the risks of nuclear generation, which include:

- the risks associated with storage, handling and disposal of radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at NSP-Minnesota's nuclear plants.

If an incident did occur, it could have a material adverse effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities.

***Economic conditions could negatively impact our business.***

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital.

Worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. Additionally, the cost of those commodities may be higher than expected.

***Our utility operations are subject to long term planning risks.***

On a periodic basis, or as needed, our utility operations file long term resource plans with our regulators. These plans are based on numerous assumptions over the relevant planning horizon such as: sales growth, economic activity, costs, regulatory mechanisms, impact of technology on sales and production and customer response. Given the uncertainty in these planning assumptions, there is a risk that the magnitude and timing of resource additions and demand may not coincide. This could lead to under recovery of costs or insufficient resources to meet customer demand.

***Our operations could be impacted by war, acts of terrorism, threats of terrorism or disruptions in normal operating conditions due to localized or regional events.***

Our generation plants, fuel storage facilities, transmission and distribution facilities and information systems may be targets of terrorist activities that could disrupt our ability to produce or distribute some portion of our energy products. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair and insure our assets, which could have a material adverse impact on our financial condition and results of operations. The potential for terrorism has subjected our operations to increased risks and could have a material adverse effect on our business. While we have already incurred increased costs for security and capital expenditures in response to these risks, we may experience additional capital and operating costs to implement security for our plants, including our nuclear power plants under the NRC's design basis threat requirements, such as additional physical plant security and additional security personnel.

The insurance industry has also been affected by these events and the availability of insurance covering risks we and our competitors typically insure against may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business. Because our generation, transmission systems, and local natural gas distribution companies are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by an event (severe storm, severe temperature extremes, generator or transmission facility outage, pipeline rupture, railroad disruption, sudden and significant increase or decrease in wind generation) within our operating systems or on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results.

***We are subject to business continuity risks associated with our ability to respond to unforeseen events.***

Our response to unforeseen events will, in part, determine the financial impact of the event on our financial condition and results. It's difficult to predict the magnitude of such events and associated impacts.

***We are subject to information security risks.***

A security breach of our information systems could subject us to financial harm associated with theft or inappropriate release of certain types of information, including, but not limited to, customer or system operating information. We are unable to quantify the potential impact of such an event.

***Rising energy prices could negatively impact our business.***

Higher fuel costs could significantly impact our results of operations if requests for recovery are unsuccessful. In addition, higher fuel costs could reduce customer demand or increase bad debt expense, which could also have a material impact on our results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

***Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.***

Our electric and natural gas utility businesses are seasonal businesses and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition and results of operations.

***Our natural gas distribution activities involve numerous risks that may result in accidents and other operating risks and costs.***

There are inherent in our natural gas distribution activities a variety of hazards and operating risks, such as leaks, explosions and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses.

The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. For our distribution lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damages resulting from these risks is greater.

***Increased risks of regulatory penalties could negatively impact our business.***

The Energy Act increased the FERC's civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of $1 million per violation per day. Effective June 2007, 83 electric reliability standards that were historically subject to voluntary compliance could negativity impact our business became mandatory and subject to potential civil penalties for violations. If a serious reliability incident did occur, it could have a material adverse effect on our operations or financial results.

***Increasing costs associated with our defined benefit retirement plans and other employee-related benefits may adversely affect our results of operations, financial position, or liquidity.***

We have defined benefit and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Therefore, our funding requirements and related contributions may change in the future.

***Increasing costs associated with health care plans may adversely affect our results of operations, financial position or liquidity.***

The costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements associated with our health care plans may adversely affect our results of operations, financial position, or liquidity.

## Risks Associated with Our Holding Company Structure

***We must rely on cash from our subsidiaries to make dividend payments.***

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness and pay dividends, depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for that purpose or for dividends on our common stock, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and/or contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of equity ratios, working capital or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

If our utility subsidiaries were to cease making dividend payments, it could adversely affect our ability to pay dividends on our common stock and preferred stock or otherwise meet our financial obligations.

***Certain provisions of law, as well as provisions in our bylaws and shareholder rights plan, may make it more difficult for others to obtain control of us, even though some shareholders might consider this favorable.***

We are a Minnesota corporation and certain anti-takeover provisions of Minnesota law apply to us and create various impediments to the acquisition of control of us or to the consummation of certain business combinations with us. In addition, our shareholder rights plan contains provisions, which may make it more difficult to effect certain business combinations with us without the approval of our board of directors. Finally, certain federal and state utility regulatory statutes may also make it difficult for another party to acquire a controlling interest in us. These provisions of law and of our corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

## Item 1B — Unresolved SEC Staff Comments

None.

## Item 2 — Properties

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

Electric utility generating stations:

## NSP-Minnesota

| Station, City and Unit | Fuel | Installed | Summer 2007 Net Dependable Capability (MW) |
|---|---|---|---|
| Steam: | | | |
| Sherburne-Becker, MN | | | |
| Unit 1 | Coal | 1976 | 697 |
| Unit 2 | Coal | 1977 | 682 |
| Unit 3 | Coal | 1987 | 504[a] |
| Prairie Island-Welch, MN | | | |
| Unit 1 | Nuclear | 1973 | 551 |
| Unit 2 | Nuclear | 1974 | 545 |
| Monticello-Monticello, MN | Nuclear | 1971 | 572 |
| King-Bayport, MN | Coal | 1968 | 528 |
| Black Dog-Burnsville, MN | | | |
| 2 Units | Coal/Natural Gas | 1955-1960 | 282 |
| 2 Units | Natural Gas | 1987-2002 | 298 |
| High Bridge-St. Paul, MN | | | |
| 2 Units | Coal | 1956-1959 | 271[b] |
| Riverside-Minneapolis, MN | | | |
| 2 Units | Coal | 1964-1987 | 381 |
| Combustion Turbine: | | | |
| Angus Anson-Sioux Falls, SD | | | |
| 3 Units | Natural Gas | 1994-2005 | 384 |
| Inver Hills-Inver Grove Heights, MN | | | |
| 6 Units | Natural Gas | 1972 | 350 |
| Blue Lake-Shakopee, MN | | | |
| 6 Units | Natural Gas | 1974-2005 | 490 |
| Other | Various | Various | 169 |
| | | Total | 6,704 |

(a) Based on NSP-Minnesota's ownership interest of 59 percent.

(b) High Bridge coal units were removed from service on Aug. 31, 2007.

## NSP-Wisconsin

| Station, City and Unit | Fuel | Installed | Summer 2007 Net Dependable Capability (MW) |
|---|---|---|---|
| Combustion Turbine: | | | |
| Flambeau Station-Park Falls, WI - 1 Unit | Natural Gas/Oil | 1969 | 13 |
| Wheaton-Eau Claire, WI - 6 Units | Natural Gas/Oil | 1973 | 353 |
| French Island-La Crosse, WI - 2 Units | Oil | 1974 | 147 |
| Steam: | | | |
| Bay Front-Ashland, WI - 3 Units | Coal/Wood/Natural Gas | 1948-1956 | 73 |
| French Island-La Crosse, WI - 2 Units | Wood/RDF[a] | 1940-1948 | 29 |
| Hydro: | | | |
| 19 Plants | | Various | 254 |
| | | Total | 869 |

(a) RDF is refuse-derived fuel, made from municipal solid waste.

## PSCo

| Station, City and Unit | Fuel | Installed | Summer 2007 Net Dependable Capability (MW) |
|---|---|---|---|
| Steam: | | | |
| Arapahoe-Denver, CO 2 Units | Coal | 1951-1955 | 156 |
| Cameo-Grand Junction, CO 2 Units | Coal | 1957-1960 | 73 |
| Cherokee-Denver, CO 4 Units | Coal | 1957-1968 | 717 |
| Comanche-Pueblo, CO 2 Units | Coal | 1973-1975 | 660 |
| Craig-Craig, CO 2 Units | Coal | 1979-1980 | 83[(a)] |
| Hayden-Hayden, CO 2 Units | Coal | 1965-1976 | 237[(b)] |
| Pawnee-Brush, CO | Coal | 1981 | 505 |
| Valmont-Boulder, CO | Coal | 1964 | 186 |
| Zuni-Denver, CO 2 Units | Natural Gas/Oil | 1948-1954 | 107 |
| Combustion Turbines: | | | |
| Fort St. Vrain-Platteville, CO 4 Units | Natural Gas | 1972-2001 | 690 |
| Various Locations 6 Units | Natural Gas | Various | 174 |
| Hydro: | | | |
| Various Locations 12 Units | | Various | 32 |
| Cabin Creek-Georgetown, CO Pumped Storage | | 1967 | 210 |
| Wind: | | | |
| Ponnequin-Weld County, CO | | 1999-2001 | — |
| Diesel Generators: | | | |
| Cherokee-Denver, CO 2 Units | | 1967 | 6 |
| | | Total | 3,836 |

(a) Based on PSCo's ownership interest of 9.7 percent.

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

## SPS

| Station, City and Unit | Fuel | Installed | Summer 2007 Net Dependable Capability (MW) |
|---|---|---|---|
| Steam: | | | |
| Harrington-Amarillo, TX 3 Units | Coal | 1976-1980 | 1,041 |
| Tolk-Muleshoe, TX 2 Units | Coal | 1982-1985 | 1,080 |
| Jones-Lubbock, TX 2 Units | Natural Gas | 1971-1974 | 486 |
| Plant X-Earth, TX 4 Units | Natural Gas | 1952-1964 | 442 |
| Nichols-Amarillo, TX 3 Units | Natural Gas | 1960-1968 | 457 |
| Cunningham-Hobbs, NM 2 Units | Natural Gas | 1957-1965 | 267 |
| Maddox-Hobbs, NM | Natural Gas | 1967 | 118 |
| CZ-2-Pampa, TX | Purchased Steam | 1979 | 26 |
| Moore County-Amarillo, TX | Natural Gas | 1954 | 48 |
| Gas Turbine: | | | |
| Carlsbad-Carlsbad, NM | Natural Gas | 1968 | 11 |
| CZ-1-Pampa, TX | Hot Nitrogen | 1965 | 13 |
| Maddox-Hobbs, NM | Natural Gas | 1976 | 60 |
| Riverview-Electric City, TX | Natural Gas | 1973 | 23 |
| Cunningham-Hobbs, NM 2 Units | Natural Gas | 1998 | 218 |
| Diesel: | | | |
| Tucumcari, NM 6 Units | | 1941-1979 | — |
| | | Total | 4,290 |

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2007:

| Conductor Miles | NSP-Minnesota | NSP-Wisconsin | PSCo | SPS |
|---|---|---|---|---|
| 500 KV | 2,917 | — | — | — |
| 345 KV | 5,564 | 1,312 | 957 | 5,139 |
| 230 KV | 1,801 | — | 11,393 | 9,420 |
| 161 KV | 295 | 1,495 | — | — |
| 138 KV | — | — | 92 | — |
| 115 KV | 6,577 | 1,529 | 4,871 | 10,878 |
| Less than 115 KV | 82,100 | 31,807 | 72,027 | 22,724 |

Electric utility transmission and distribution substations at Dec. 31, 2007:

| | NSP-Minnesota | NSP-Wisconsin | PSCo | SPS |
|---|---|---|---|---|
| Quantity | 367 | 203 | 216 | 432 |

Gas utility mains at Dec. 31, 2007:

| Miles | NSP-Minnesota | NSP-Wisconsin | PSCo | WGI |
|---|---|---|---|---|
| Transmission | 135 | — | 2,306 | 12 |
| Distribution | 9,446 | 2,172 | 20,815 | — |

## Item 3 — Legal Proceedings

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

## Additional Information

For a discussion of legal claims and environmental proceedings, see Note 15 to the consolidated financial statements under Item 8, incorporated by reference. For a discussion of proceedings involving utility rates and other regulatory matters, see Pending and Recently Concluded Regulatory Proceedings under Item 1, Management's Discussion and Analysis under Item 7, and Note 14 to the consolidated financial statements under Item 8, incorporated by reference.

## Item 4 — Submission of Matters to a Vote of Security Holders

No issues were submitted for a vote during the fourth quarter of 2007.

# PART II

## Item 5 — Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

### Quarterly Stock Data

Xcel Energy's common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2007 and 2006 and the dividends declared per share during those quarters.

| | High | Low | Dividends |
|---|---|---|---|
| **2007** | | | |
| First Quarter | $24.94 | $22.75 | $0.2225 |
| Second Quarter | 25.03 | 19.97 | 0.2300 |
| Third Quarter | 22.41 | 19.59 | 0.2300 |
| Fourth Quarter | 23.50 | 20.70 | 0.2300 |
| **2006** | | | |
| First Quarter | $19.61 | $17.91 | $0.2150 |
| Second Quarter | 19.76 | 17.80 | 0.2225 |
| Third Quarter | 21.05 | 18.96 | 0.2225 |
| Fourth Quarter | 23.63 | 20.56 | 0.2225 |

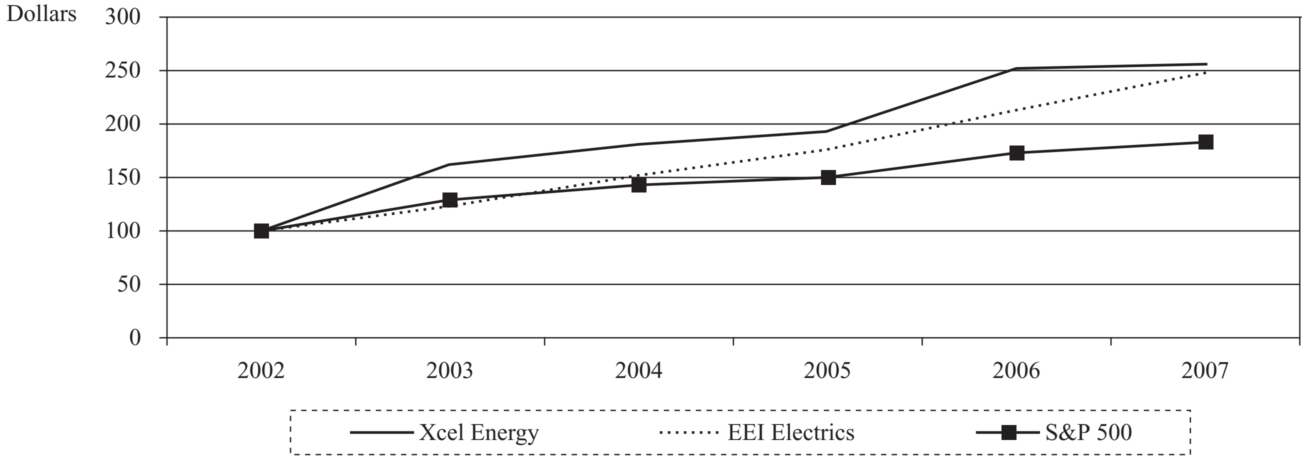
Book value per share at Dec. 31, 2007, was $14.70. The number of common shareholders of record as of Dec. 31, 2007 was 91,000. Xcel Energy's Restated Articles of Incorporation provide for certain restrictions on the payment of cash dividends on common stock.

At Dec. 31, 2007 and 2006, the payment of cash dividends on common stock was not restricted. For further discussion of Xcel Energy's dividend policy, see Liquidity and Capital Resources under Item 7.

The following compares our cumulative total shareholder return on common stock with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, and the EEI Investor-Owned Electrics Index over the last five fiscal years (assuming a $100 investment in each vehicle on Dec. 31, 2002, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 61 companies and is a broad measure of industry performance.

**COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN***
Among Xcel Energy, The S&P 500
and The EEI Investor-Owned Electrics




* $100 invested on 12/31/02 in stock or index — including reinvestment of dividends. Fiscal years ending December 31.

| | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|---|
| Xcel Energy | $100 | $162 | $181 | $193 | $252 | $256 |
| S&P 500 | 100 | 129 | 143 | 150 | 173 | 183 |
| EEI Investor-Owned Electrics | 100 | 123 | 152 | 176 | 213 | 248 |

See Item 12 for information concerning securities authorized for issuance under equity compensation plans.

# Item 6 — Selected Financial Data

| | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| | (Millions of Dollars, Except Share and Per-Share Data) | | | | |
| Operating revenues | $ 10,034 | $ 9,840 | $ 9,625 | $ 8,216 | $ 7,731 |
| Operating expenses | 8,683 | 8,663 | 8,533 | 7,140 | 6,607 |
| Income from continuing operations | 576 | 569 | 499 | 522 | 523 |
| Net income | 577 | 572 | 513 | 356 | 622 |
| Earnings available for common stock | 573 | 568 | 509 | 352 | 618 |
| Average number of common shares outstanding (000's) | 416,139 | 405,689 | 402,330 | 399,456 | 398,765 |
| Average number of common and potentially dilutive shares outstanding (000's) | 433,131 | 429,605 | 425,671 | 423,334 | 418,912 |
| Earnings per share from continuing operations — basic | $ 1.38 | $ 1.39 | $ 1.23 | $ 1.30 | $ 1.30 |
| Earnings per share from continuing operations — diluted | 1.35 | 1.35 | 1.20 | 1.26 | 1.26 |
| Earnings per share — basic | 1.38 | 1.40 | 1.26 | 0.88 | 1.55 |
| Earnings per share — diluted | 1.35 | 1.36 | 1.23 | 0.87 | 1.50 |
| Dividends declared per share | 0.91 | 0.88 | 0.85 | 0.81 | 0.75 |
| Total assets | 23,185 | 21,958 | 21,505 | 20,305 | 20,205 |
| Long-term debt[(b)] | 6,342 | 6,450 | 5,898 | 6,493 | 6,494 |
| Book value per share | 14.70 | 14.28 | 13.37 | 12.99 | 12.95 |
| Return on average common equity | 9.5% | 10.1% | 9.6% | 6.8% | 12.6% |
| Ratio of earnings to fixed charges[(a)] | 2.2 | 2.2 | 2.1 | 2.2 | 2.2 |

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

(b) Long-term debt includes only debt of continuing operations.

# Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

## Business Segments and Organizational Overview

## Continuing Operations

Xcel Energy is a public utility holding company. In 2007, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 8 states. These utility subsidiaries are NSP-Minnesota; NSP-Wisconsin; PSCo; and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WGI, an interstate natural gas pipeline, these companies comprise the continuing regulated utility operations.

Xcel Energy's nonregulated subsidiary reported in continuing operations is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

## Discontinued Operations

See Note 3 to the consolidated financial statements for discussion of discontinued operations.

## Forward-Looking Statements

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," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" 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 the availability of credit and its 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; actions of credit rating agencies; 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; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including "Risk Factors" in Item 1A of Xcel Energy's Form 10-K for the year ended Dec. 31, 2007 and Exhibit 99.01 to Xcel Energy's Form 10-K for the year ended Dec. 31, 2007.

## Management's Strategic Plan

Xcel Energy's strategy, called Building the Core, has three primary focuses: environmental leadership, achieving financial objectives and optimizing the management of a portfolios of operating utilities. In summary, our objective is to embrace growing customer demand and environmental initiatives by investing in our core utility businesses and earning a reasonable return on our invested capital. Below is a detailed discussion of our three primary focuses and how they support our overall Building the Core strategy.

### *Xcel Energy's Environmental Leadership*

Xcel Energy has adopted environmental leadership as a primary focus, forming the cornerstone of all our strategic initiatives. Xcel Energy believes that our environmental leadership meets customer and policy maker expectations and, in turn, creates significant shareholder value.

As a portfolio of regulated utilities, Xcel Energy has an obligation to serve its customers by providing them with reasonably priced, reliable electric and gas services. However, Xcel Energy's strategy goes beyond this traditional mission. Under the environmental leadership strategy, Xcel Energy assesses and takes prudent, balanced steps to reduce the impact of our operations on the environment while promoting technological and public policy advancements that will encourage a cleaner electric system. In light of the capital-intensive nature of our business, including the long life of

Xcel Energy's capital investments, Xcel Energy assesses and takes prudent steps to reduce the overall risk associated with potential new environmental mandates. Finally, Xcel Energy seeks to reduce regulatory uncertainty through favorable cost recovery for environmental initiatives provided by public policy makers, including legislatures and public utilities commissions.

The foundation for Xcel Energy's environmental leadership strategy resides with its environmental policy. Under this policy, the Xcel Energy Board of Directors, acting through the Nuclear, Environmental and Safety Committee, oversees Xcel Energy's environmental compliance program and policy initiatives. The policy is available on our website at www.xcelenergy.com. Xcel Energy has created an environmental management system that provides employees with training and documentation of Xcel Energy's compliance responsibilities, creates processes designed to minimize the risk of noncompliance and audits Xcel Energy's environmental performance. Environmental performance is incorporated into officer and employee job responsibilities and compensation.

Xcel Energy pursues environmental leadership through management of environmental policy initiatives. Xcel Energy actively evaluates public policy proposals and promotes environmental initiatives that are designed to create shareholder value, reduce financial risk and provide growth opportunities. These initiatives include the following:

- Xcel Energy has implemented voluntary emission reduction programs in Minnesota and Colorado. These programs have resulted or will result in substantial emission reductions from existing facilities. They also incorporate enhanced cost recovery mechanisms that provide shareholders with favorable returns for the associated emission reduction investments.
- Xcel Energy is the nation's largest utility wind energy provider. Xcel Energy is pursuing new wind, solar and other renewable energy acquisitions and investments to meet some of the nation's most aggressive renewable energy standards in the states in which Xcel Energy operates. Xcel Energy has worked with state policy makers to design these standards to incorporate favorable cost recovery mechanisms and investment opportunities.
- Xcel Energy is a leader in promoting new, clean energy technologies. Xcel Energy has undertaken small-scale projects to study the technical and economic aspects of energy storage and the use of hydrogen. Xcel Energy is a leader in supporting the advancement of solar energy technology. Xcel Energy is also exploring the use of clean coal and is evaluating whether and how to best take advantage of state and federal incentives for clean coal development.
- Xcel Energy has a number of environmental initiatives focused on our customers. In Colorado, Xcel Energy has the largest customer-driven wind program in the nation (WindSource) and a growing customer-sited solar program, known as "Solar*Rewards." Xcel Energy also has an increasing portfolio of customer energy efficiency and conservation programs and is working with state commissions to enhance the financial incentives associated with our programs. Xcel Energy is also working to apply intelligence to its electric grid (creating a "SmartGrid") to provide customers with more choice, reliability and control over their energy use.

While Xcel Energy is not currently subject to state or federal regulation of its GHG emissions, as one of the nation's largest electric generating companies, Xcel Energy is committed to addressing climate change through efforts to reduce its GHG emissions. Xcel Energy's current electric generating portfolio includes coal- and gas-fired plants that are projected to emit approximately 67 million tons of $CO_2$ in 2007. Purchased generation is expected to emit approximately 18 million tons of $CO_2$ in 2007. There has been a combined cumulative reduction of over 18.5 million tons of $CO_2$ since 2003. Xcel Energy is implementing aggressive future resource development and conservation plans that will further reduce the company's $CO_2$ emissions, both in absolute terms and per Kwh of electricity produced. See Management's Discussion and Analysis for further discussion.

In 2007, Xcel Energy filed resource plans in Minnesota and Colorado that propose significant new clean energy resources. If the state commissions approve these plans, Xcel Energy would:

- Increase overall system wind capacity from approximately 2,800 MW by the end of 2007 to approximately 6,000 MW by 2020;
- Add 225 MW of concentrating solar thermal technology;
- Reduce retail demand through energy efficiency and conservation programs by 1.1 percent in Minnesota and 0.7 percent in Colorado;
- Retire and replace approximately 230 MW of coal-fired electric generation;
- Improve the efficiency of and reduce $CO_2$, mercury, $SO_2$ and NOx emissions at several existing fossil plants; and

- Upgrade the efficiency and capacity of existing nuclear facilities.

Xcel Energy has designed these plans so that, depending on fuel, commodity and other assumptions, Xcel Energy would maintain a reasonably priced product and continue to provide reliable power to our customers. At the same time, if approved, the plans would result in a significant reduction in $CO_2$ emissions. The proposed Minnesota plan would reduce NSP-Minnesota's $CO_2$ emissions by 22 percent below 2005 levels by 2020. The proposed Colorado plan would reduce PSCo's $CO_2$ emissions by 10 percent below 2005 levels by 2017 and position PSCo to propose additional reductions to achieve a 20 percent reduction by 2020.

Our environmental leadership strategy has resulted in numerous environmental awards and recognition. For example, Xcel Energy was named to the Dow Jones Sustainability Index for North America for 2007-2008, the second consecutive year that Xcel Energy has earned this distinction. Xcel Energy strives to provide the public with detailed information regarding environmental performance and risk. Among other things, our utility companies operating in Minnesota, Colorado, and New Mexico use a carbon proxy cost mandated by the state commissions to evaluate the impact of potential future $CO_2$ regulation on its future resource acquisition plans. Xcel Energy publishes a Triple Bottom Line Report annually, which is available on our website, www.xcelenergy.com. The Triple Bottom Line report discloses Xcel Energy's environmental, economic and social performance. Xcel Energy also provides detailed information to environmental research organizations, such as Trucost, the Carbon Disclosure Project and the Climate Registry.

*Achieving Financial Objectives*

Xcel Energy's financial objectives of Building the Core also has three phases: obtaining legislative and regulatory support for large investment initiatives, investing in the utility business and earning a fair return on utility system investments.

The first phase, as noted above, is obtaining legislative and regulatory support for large investment initiatives, prior to making the investment. To avoid excessive risk to Xcel Energy, it is critical that Xcel Energy reduce regulatory uncertainty before making large capital investments. Xcel Energy has accomplished this for both the MERP in Minnesota and the Comanche 3 coal unit in Colorado. Transmission legislation has been passed in Minnesota, Colorado, Texas and several other jurisdictions where Xcel Energy operates.

The second phase is investing in the utility business. In addition to Xcel Energy's normal level of capital investment, Xcel Energy expects to have significant investment opportunity, in part attributable to the environmental strategy described above. Those opportunities include the following:

- Approximately $1 billion through 2010 for MERP, a project to convert an aging coal-fired plant to a natural gas plant and to install pollution control at another plant. During 2007, the initial phase of this project was completed with the successful conversion of the Allen S. King plant to a natural gas facility;
- Approximately $1 billion through 2010 for Comanche 3, a project to build an additional coal unit in Colorado;
- Approximately $215 million for the planned addition of two gas fired units totaling 300 MW at the Fort St. Vrain generating facility located in Colorado;
- A proposed $1 billion investment through 2015 to extend the lives and increase the output of two nuclear facilities, Monticello and Prairie Island;
- A proposed $1.1 billion investment through 2015 to add capacity and reduce emissions at the Sherco coal fired plant;
- A planned investment by the CapX 2020 coalition of utilities ranging from $1.3 billion to 1.6 billion between 2008 and 2015 to expand the transmission system in the upper Midwest, of which Xcel Energy's share of the investment would be approximately $700 million, representing the first phase of CapX 2020; and
- Several other potential environmental initiatives, including substantial wind generation investment described above and outlined in the recently proposed Colorado and Minnesota resource plans.

As a result of these investments, as well as continued investments in the transmission and distribution system, Xcel Energy expects that the rate base, or the amount on which Xcel Energy earns a return, will grow on average annually by more than seven percent from 2006 through 2011.

The third phase is earning a fair return on utility system investments. To this end, the regulatory strategy is to receive regulatory approval for rate riders as well as general rate cases. A rate rider is a mechanism that allows recovery of certain costs and returns on investments without the costs and delays of filing a rate case. These riders allow for timely revenue recovery of the costs of large projects or other costs that vary over time. As an example, a rider for MERP went into effect in January 2006, allowing Xcel Energy to earn a return on the project, while each of the facilities is being constructed.

Xcel Energy's regulatory strategy is based on filing reasonable rate requests designed to provide recovery of legitimate expenses and a return on utility investments. Xcel Energy believes that the public utility commissions will provide reasonable recovery, and it is important to note that the financial plans include this assumption. Constructive results over the last several years are evidence of reasonable regulatory treatment and give Xcel Energy confidence that Xcel Energy is pursuing the right strategy. These rate cases, as well others planned for 2008 and beyond, are some of the building blocks of the earnings growth plan.

With any strategic plan, there are goals and objectives. Xcel Energy feels the following financial objectives continue to be both realistic and achievable.

- Annual earnings-per-share growth rate target of 5 percent to 7 percent;
- Annual dividend increases of 2 percent to 4 percent; and
- Senior unsecured debt credit ratings in the BBB+ to A range.

Successful execution of the Building the Core strategic plan should allow Xcel Energy to achieve the outlined financial objectives, which in turn should provide investors with an attractive total return on a low-risk investment.

***Optimizing the Management of a Portfolio of Operating Utilities***

Optimizing the management of a portfolio of operating utilities is the third area of focus related to the Building the Core strategy. Even though Xcel Energy ultimately manages the business based on the revenue streams provided by electric and natural gas, Xcel Energy continues to evolve the management of the portfolio of utility investments. While Xcel Energy has four separate operating companies, there are certain similarities and differences that require a new approach to more effectively manage this portfolio. More specifically, Xcel Energy's goal is to build on the similarities among the companies, which maximizes efficiencies from centralized management and deployment of common initiatives. Examples include market branding and environmental policy research. From an organizational perspective, examples include corporate center services as well as certain operational functions, such as asset management, environmental compliance and safety.

At the same time, Xcel Energy realizes there are unique differences in each of our service territories such as local community focus and priorities, regulatory environment, physical plant infrastructure and age, weather, as well as others that require Xcel Energy to organize / align these utility specific areas to most effectively address these utility distinct characteristics. To that end, Xcel Energy has operating presidents, each located in their respective jurisdiction. The objective of this organizational structure is to optimize Xcel Energy's operating efficiency while maximizing accountability.

## 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 consolidated financial statements and the related notes to consolidated financial statements. All note references refer to the notes to consolidated financial statements.

## Summary of Financial Results

The following table summarizes the earnings contributions of Xcel Energy's business segments on the basis of GAAP. Continuing operations consist of the following:

- Regulated utility subsidiaries, operating in the electric and natural gas segments; and
- Other nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of the following:

- Quixx Corp., a major portion of which was sold in October 2006;

- Utility Engineering Corp., which was sold in April 2005;
- Seren, a portion of which was sold in November 2005 with the remainder sold in January 2006;
- Cheyenne, which was sold in January 2005;
- NRG, which emerged from bankruptcy and was divested in late 2003; and
- Xcel Energy International and e prime Inc. (e prime), which were classified as held for sale in late 2003 based on the decision to divest them.

See Note 3 to the consolidated financial statements for a further discussion of discontinued operations.

| | Contribution to earnings | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Millions of Dollars) | | |
| **GAAP income by segment** | | | |
| Regulated electric utility income — continuing operations | $554.7 | $503.1 | $440.6 |
| Regulated natural gas utility income — continuing operations | 108.0 | 70.6 | 71.2 |
| Other regulated utility income[(a)] | (26.7) | 32.3 | 27.6 |
| Total utility income — continuing operations | 636.0 | 606.0 | 539.4 |
| Holding company costs and other results[(a)] | (60.1) | (37.3) | (40.3) |
| Total income — continuing operations | 575.9 | 568.7 | 499.1 |
| Regulated utility income — discontinued operations | — | 3.0 | 0.2 |
| Other nonregulated income — discontinued operations | 1.4 | 0.1 | 13.7 |
| Total income — discontinued operations | 1.4 | 3.1 | 13.9 |
| Total GAAP net income | $577.3 | $571.8 | $513.0 |

| | Contribution to earnings per share | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **GAAP earnings per share contribution by segment** | | | |
| Regulated electric utility — continuing operations | $1.28 | $1.17 | $1.04 |
| Regulated natural gas utility — continuing operations | 0.25 | 0.16 | 0.17 |
| Other regulated utility[(a)] | (0.06) | 0.08 | 0.06 |
| Total utility earnings per share — continuing operations | 1.47 | 1.41 | 1.27 |
| Holding company costs and other results[(a)] | (0.12) | (0.06) | (0.07) |
| Total earnings per share — continuing operations | 1.35 | 1.35 | 1.20 |
| Regulated utility earnings — discontinued operations | — | 0.01 | — |
| Other nonregulated earnings — discontinued operations | — | — | 0.03 |
| Total earnings per share — discontinued operations | — | 0.01 | 0.03 |
| Total GAAP earnings per share — diluted | $1.35 | $1.36 | $1.23 |

(a) Not a reportable segment. Included in All Other segment results in Note 18 to the consolidated financial statements.

Earnings from continuing operations for 2007 were higher than in 2006. The increase in 2007 earnings were primarily attributed to higher electric and gas margins, reflecting various rate increases, weather-normalized retail sales growth, higher rider recovery, and the impact of favorable temperatures, which also increased sales. Partially offsetting these positive factors were higher operating and maintenance expense, increased interest expense and a higher effective tax rate.

Earnings from continuing operations for 2006 were higher than in 2005. The increase in 2006 earnings was primarily due to stronger base electric utility margin. The higher margin reflects electric rate increases in various jurisdictions, weather-adjusted retail electric sales growth and revenue associated with investments in MERP. In addition, earnings increased due to the recognition of income tax benefits. Partially offsetting these positive factors were expected increases in expenses for operations, maintenance and depreciation and lower short-term wholesale margins.

During 2007, Xcel Energy entered into a settlement agreement with the IRS related to a dispute associated with its COLI program. Excluding this settlement, along with the earnings associated with this insurance program, Xcel Energy's ongoing 2007 earnings were $612 million, or $1.43 per share, compared with 2006 ongoing earnings of $548 million or $1.30 per share. The following table provides a reconciliation of GAAP earnings and earnings per share to ongoing earnings and earnings per share for 2007, 2006 and 2005.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Millions of Dollars) | |
| Ongoing earnings | $ 612.0 | $548.2 | $480.4 |
| PSRI earnings | 23.4 | 20.5 | 18.7 |
| Interest, penalties and tax related to IRS COLI settlement | (59.5) | — | — |
| Total continuing operations | 575.9 | 568.7 | 499.1 |
| Discontinued operations | 1.4 | 3.1 | 13.9 |
| Total GAAP earnings | $ 577.3 | $571.8 | $513.0 |

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Ongoing earnings per share | $ 1.43 | $1.30 | $1.15 |
| PSRI earnings | 0.05 | 0.05 | 0.05 |
| Interest, penalties and tax related to IRS COLI settlement | (0.13) | — | — |
| Earnings per share — continuing operations | 1.35 | 1.35 | 1.20 |
| Discontinued operations | — | 0.01 | 0.03 |
| Total GAAP earnings per share | $ 1.35 | $1.36 | $1.23 |

As a result of the termination of the COLI program, Xcel Energy's management believes that ongoing earnings provide a more meaningful comparison of earnings results between different periods in which the COLI program was in place and is more representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation and when communicating its earnings outlook to analysts and investors.

Income from discontinued operations in 2005 includes the positive impact of a $17 million tax benefit recorded to reflect the final resolution of Xcel Energy's divested interest in NRG. This was partially offset by Seren's operating losses during 2005.

| | Contribution to earnings | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Earnings Contribution by Company** | | | |
| NSP-Minnesota | 45.9% | 47.4% | 46.6% |
| PSCo | 51.0 | 41.5 | 41.7 |
| SPS | 5.7 | 8.1 | 12.5 |
| NSP-Wisconsin | 6.5 | 7.4 | 5.0 |
| Total regulated utility contribution | 109.1 | 104.4 | 105.8 |
| Holding company and other subsidiaries | (9.1) | (4.4) | (5.8) |
| Total earnings contributions | 100.0% | 100.0% | 100.0% |

***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. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses. The impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature.

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 2007 increased earnings by an estimated 6 cents per share;
- Weather in 2006 increased earnings by an estimated 2 cents per share; and
- Weather in 2005 decreased earnings by an estimated 3 cents per share.

## Statement of Operations Analysis — Continuing Operations

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

## Electric Utility, Short-Term Wholesale and Commodity Trading Margins

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and cost changes in fuel and purchased power. Due to fuel and purchased energy cost-recovery mechanisms for customers in most states, the fluctuations in these costs do not materially affect electric utility margin.

Xcel Energy has two distinct forms of wholesale sales: short-term wholesale and commodity trading. Short-term wholesale refers to energy-related purchase and sales activity, and the use of financial instruments associated with the fuel required for, and energy produced from, Xcel Energy's generation assets or the energy and capacity purchased to serve native load. Commodity trading is not associated with Xcel Energy's generation assets or the energy and capacity purchased to serve native load. Short-term wholesale and commodity trading activities are considered part of the electric utility segment.

Short-term wholesale and commodity trading margins reflect the estimated impact of regulatory sharing of margins, if applicable. Commodity trading revenues are reported net of related costs (i.e., on a margin basis) in the consolidated statements of income. Commodity trading costs include purchased power, transmission, broker fees and other related costs.

The following table details the revenue and margin for base electric utility, short-term wholesale and commodity trading activities:

| | Base Electric Utility | Short-Term Wholesale | Commodity Trading | Consolidated Totals |
|---|---|---|---|---|
| | (Millions of Dollars) | | | |
| **2007** | | | | |
| Electric utility revenues (excluding commodity trading) | $ 7,611 | $ 227 | $ — | $ 7,838 |
| Electric fuel and purchased power-utility | (3,930) | (207) | — | (4,137) |
| Commodity trading revenues | — | — | 289 | 289 |
| Commodity trading expenses | — | — | (279) | (279) |
| Gross margin before operating expenses | $ 3,681 | $ 20 | $ 10 | $ 3,711 |
| Margin as a percentage of revenues | 48.4% | 8.8% | 3.5% | 45.7% |
| **2006** | | | | |
| Electric utility revenues (excluding commodity trading) | $ 7,387 | $ 201 | $ — | $ 7,588 |
| Electric fuel and purchased power-utility | (3,925) | (178) | — | (4,103) |
| Commodity trading revenues | — | — | 610 | 610 |
| Commodity trading expenses | — | — | (590) | (590) |
| Gross margin before operating expenses | $ 3,462 | $ 23 | $ 20 | $ 3,505 |
| Margin as a percentage of revenues | 46.9% | 11.4% | 3.3% | 42.8% |
| **2005** | | | | |
| Electric utility revenues (excluding commodity trading) | $ 7,038 | $ 196 | $ — | $ 7,234 |
| Electric fuel and purchased power-utility | (3,802) | (120) | — | (3,922) |
| Commodity trading revenues | — | — | 730 | 730 |
| Commodity trading expenses | — | — | (720) | (720) |
| Gross margin before operating expenses | $ 3,236 | $ 76 | $ 10 | $ 3,322 |
| Margin as a percentage of revenues | 46.0% | 38.8% | 1.4% | 41.7% |

The following summarizes the components of the changes in base electric utility revenues and base electric utility margin for the years ended Dec. 31:

***Base Electric Utility Revenues***

| | 2007 vs. 2006 |
|---|---|
| | (Millions of Dollars) |
| PSCo electric retail rate increase | $112 |
| Retail sales growth (excluding weather impact) | 49 |
| Transmission revenues | 32 |
| MERP rider | 29 |
| Conservation and non-fuel riders (partially offset in O&M expense) | 26 |
| Miscellaneous revenues (partially offset in O&M expense) | 17 |
| Estimated impact of weather | 16 |
| Firm wholesale | 15 |
| Fuel and purchased power cost recovery | (66) |
| Other | (6) |
| Total increase in base electric utility revenues | $224 |

***2007 Comparison with 2006 —*** Base electric utility revenues increased due to a PSCo electric retail rate increase, weather-normalized retail sales growth of approximately 1.7 percent, higher transmission revenues, higher recovery from the MERP rider, which recovers financing and other costs related the MERP construction projects and higher conservation and non-fuel rider recovery, mostly from the RESA and DSM riders at PSCo. Lower fuel and purchased power costs, largely recovered from customers, partially offset the positive variances.

| | 2006 vs. 2005 |
|---|---|
| | (Millions of Dollars) |
| NSP-Minnesota electric rate changes | $129 |
| Fuel and purchased power cost recovery | 61 |
| Sales growth (excluding weather impact) | 45 |
| NSP-Wisconsin rate case | 41 |
| MERP rider | 38 |
| Conservation and non-fuel riders (partially offset in O&M expense) | 24 |
| Quality of service obligations | 12 |
| SPS Texas surcharge decision | (8) |
| SPS FERC 206 rate refund accrual | (8) |
| Other | 15 |
| Total increase in base electric utility revenues | $349 |

***2006 Comparison with 2005 —*** Base electric utility revenues increased due to rate increases in Minnesota and Wisconsin, higher fuel and purchased power costs, largely recoverable from customers, weather-normalized retail sales growth of approximately 1.8 percent, and the implementation of the MERP rider to recover financing and other costs related the MERP construction projects.

***Base Electric Utility Margin***

| | 2007 vs. 2006 |
|---|---|
| | (Millions of Dollars) |
| PSCo electric retail rate increase | $112 |
| Retail sales growth (excluding weather impact) | 49 |
| MERP rider | 29 |
| Miscellaneous revenues (partially offset in O&M) | 18 |
| Estimated impact of weather | 16 |
| Transmission revenues / net of expense | 15 |
| Conservation and non-fuel riders (partially offset in O&M) | 13 |
| Firm wholesale | 11 |
| SPS regulatory settlements, including fuel cost recovery | 1 |
| Purchased capacity costs | (27) |
| NSP-Wisconsin fuel cost recovery | (14) |
| Other, including sales mix and other fuel recovery | (4) |
| Total increase in base electric utility margin | $219 |

***2007 Comparison to 2006*** — The increase in base electric margin for the year was due to PSCo electric rate increase, the impact of favorable temperatures and weather normalized retail sales growth. These items were partially offset by purchased power costs, NSP-Wisconsin fuel cost recovery and other items.

| | 2006 vs. 2005 |
|---|---|
| | (Millions of Dollars) |
| NSP-Minnesota electric rate changes | $129 |
| NSP-Wisconsin rate changes, including fuel and purchased power cost recovery | 41 |
| Sales growth (excluding weather impact) | 39 |
| MERP rider | 38 |
| Conservation and non-fuel rider revenues | 24 |
| Firm wholesale | 12 |
| Quality-of-service obligations | 12 |
| Transmission fee classification change | (26) |
| PSCo ECA incentive | (20) |
| SPS Texas surcharge decision | (8) |
| SPS FERC 206 rate refund accrual | (8) |
| Estimated impact of weather | (3) |
| Other, including certain regulatory reserves | (4) |
| Total increase in base electric utility margin | $226 |

***2006 Comparison to 2005*** — Base electric utility margins, which are primarily derived from retail customer sales, increased due to rate increases in Minnesota and Wisconsin, weather-normalized retail sales growth, the implementation of the MERP rider, and higher firm wholesale margins. Partially offsetting the increase, is a transmission fee classification change from other operating and maintenance expenses-utility in 2005 to electric utility margin in 2006, which did not impact operating income or net income. The change resulted from an analysis conducted in conjunction with the expiration and renegotiation of certain transmission agreements, resulting in better alignment of reporting such costs consistent with MISO classification. In addition, the ECA incentive earned in Colorado in 2006 resulted in a loss, as compared to a gain in 2005.

***Short-Term Wholesale and Commodity Trading Margin***

***2007 Comparison to 2006*** — Short-term wholesale and commodity trading margins decreased approximately $13 million for 2007 compared to 2006. As expected, short-term wholesale margins declined due to retail sales growth, which reduced generation available for sale in the wholesale market.

***2006 Comparison to 2005*** — As expected, short-term wholesale and commodity trading margins declined by $43 million for 2006 compared with 2005, due to retail sales growth, which reduced surplus generation available for sale in the wholesale market, reductions in the availability of the coal-fired King plant due to the MERP project, decreased opportunities to sell due to the MISO centralized dispatch market and the Minnesota rate case settlement agreement to refund to customers the majority of short-term wholesale margins attributable to Minnesota jurisdiction customers starting in 2006.

## Natural Gas Utility Revenues and Margins

The following table details the changes in natural gas utility revenues and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of wholesale natural gas purchases. However, due to purchased natural gas cost-recovery mechanisms for sales to retail customers, fluctuations in the wholesale cost of natural gas have little effect on natural gas margin. See further discussion under Factors Affecting Results of Continuing Operations.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Millions of Dollars) | |
| Natural gas utility revenues | $ 2,112 | $ 2,156 | $ 2,307 |
| Cost of natural gas purchased and transported | (1,548) | (1,645) | (1,823) |
| Natural gas utility margin | $ 564 | $ 511 | $ 484 |

The following summarizes the components of the changes in natural gas revenues and margin for the years ended Dec. 31:

*Natural Gas Revenues*

| | 2007 vs. 2006 | 2006 vs. 2005 |
|---|---|---|
| | (Millions of Dollars) | |
| Purchased natural gas cost recovery | $(128) | $(147) |
| Estimated impact of weather | 46 | (33) |
| Base rate changes — all jurisdictions | 21 | 32 |
| Transportation | 6 | 8 |
| Sales growth (decline) (excluding weather impact) | 2 | (8) |
| Other, including late payment fees | 9 | (3) |
| Total decrease in natural gas revenues | $ (44) | $(151) |

***2007 Comparison to 2006 —*** Natural gas revenues decreased primarily due to lower natural gas costs in 2007, which are recovered from customers. Interim rate increases were effective for Minnesota in January 2007 and base rates increased for Colorado and North Dakota customers in July 2007.

***2006 Comparison to 2005 —*** Natural gas revenues decreased primarily due to lower natural gas costs in 2006, which are recovered from customers. Retail natural gas weather-normalized sales declined when compared to 2005, largely due to declining use per customer.

*Natural Gas Margin*

| | 2007 vs. 2006 | 2006 vs. 2005 |
|---|---|---|
| | (Millions of Dollars) | |
| Base rate changes — all jurisdictions | $21 | $32 |
| Estimated impact of weather | 16 | (4) |
| Transportation | 6 | 8 |
| Sales growth (decline), excluding weather impact | 2 | (7) |
| Other | 8 | (2) |
| Total increase in natural gas margin | $53 | $27 |

***2007 Comparison to 2006 —*** Natural gas margins increased due to interim rate increases, which were effective for Minnesota in January 2007, and base rate increases for Colorado and North Dakota customers in July 2007.

***2006 Comparison to 2005 —*** Natural gas margins increased in 2006 due to rate increases in Colorado, Wisconsin and Minnesota. Base rate changes include a full year of new rates for Minnesota in 2006 as compared to two months of increase in 2005.

## Non-Fuel Operating Expenses and Other Items

*Other Operating and Maintenance Expenses*

| | 2007 vs. 2006 |
|---|---|
| | (Millions of Dollars) |
| Higher combustion/hydro plant costs | $ 33 |
| Higher nuclear plant operation costs | 19 |
| Recording of private fuel storage regulatory asset in 2006 | 17 |
| Higher labor costs | 16 |
| Higher conservation incentive programs (offset in electric margins) | 13 |
| Lower gains/losses on sale or disposal of assets, net | 10 |
| Higher contractor costs | 10 |
| Higher donations, including low income contributions (offset in revenues) | 10 |
| Higher material costs | 5 |
| Lower employee benefit costs | (32) |
| Lower nuclear plant outage costs | (10) |
| Lower uncollectible receivable costs | (1) |
| Other, including licenses and permits | 6 |
| Total increase in other operating and maintenance expenses | $ 96 |

*2007 Comparison to 2006* — The increase in operating and maintenance expenses for 2007 was largely driven by recording a $17 million regulatory asset for private nuclear fuel storage costs which had been previously expensed and higher net gains on sales of assets in 2006. Also, higher combustion/hydro and nuclear plant costs increased operating and maintenance expense. Offsetting these increases in operating and maintenance expenses were lower performance based incentive plan expense as well as lower healthcare expense. Also partially offsetting the increased operating and maintenance expenses were lower nuclear plant outage costs, due to two refueling outages in 2006 versus only one outage in 2007.

| | 2006 vs. 2005 (Millions of Dollars) |
|---|---|
| Transmission fees classification change | $(26) |
| Private Fuel Storage regulatory asset | (17) |
| Gains on sale or disposal of assets, net | (9) |
| Lower nuclear plant outage costs | (4) |
| Higher employee benefit costs, primarily performance-based | 38 |
| Higher combustion/hydro plant costs | 24 |
| Higher nuclear plant operating costs | 22 |
| Higher uncollectible receivable costs | 15 |
| Higher consulting costs | 8 |
| Higher conservation incentive programs (offset in electric margins) | 4 |
| Other, including fleet transportation and facilities costs | 11 |
| Total increase in other operating and maintenance expenses | $ 66 |

*2006 Comparison to 2005* — Other operating and maintenance expenses for 2006 increased $66 million, or 3.9 percent, compared with 2005. Higher employee benefit costs, which are primarily performance-based, higher nuclear and combustion/hydro plant costs were offset by lower nuclear plant outage costs, the transmission reclassification, gains on sales of assets, and the establishment of the private fuel storage regulatory asset, based on a regulatory decision.

*Depreciation and Amortization* — Depreciation and amortization expense increased by approximately $5 million, or 0.6 percent, for 2007, compared to 2006. Depreciation increased due to capital additions and was largely offset by the MPUC approval of NSP-Minnesota's remaining lives depreciation filing, which lengthened the life of the Monticello nuclear plant by 20 years, as well as certain other smaller plant life adjustments and adjustments to depreciable lives from the Texas rate case settlement. Both of these decisions were effective Jan. 1, 2007, and in total reduced depreciation expense by $45 million for the year.

Depreciation and amortization expense increased by approximately $55 million, or 7.1 percent, for 2006 compared with 2005. Decommissioning accruals increased $20 million in 2006. Normal plant additions accounted for the remaining increase in depreciation expense for 2006 over 2005.

*AFDC* — AFDC increased in total by $16 million for 2007 when compared to 2006. The increase was due primarily to large capital projects, including Comanche 3 and a portion of MERP, with long construction periods.

AFDC increased in total by approximately $14 million for 2006 when compared to 2005. The increase was due primarily to large capital projects beginning in 2005 and 2006, including MERP and Comanche 3, with long construction periods. The increase was partially offset by the current recovery from customers of the financing costs related to MERP through a MERP rider resulting in a lower recognition of AFDC.

*Interest and Other Income (Expense), Net* — Interest and other income (expense), net increased $7 million in 2007 compared to 2006. The increase is due primarily to higher interest income on temporary cash investments and the decrease in insurance policy interest expense related to COLI due to the settlement reached with the U.S. Government. In addition, interest and penalties related to the COLI settlement, increased by $43 million in 2007, due to the settlement reached with the U.S. Government.

Interest and other income (expense) net increased $3 million in 2006 compared to 2005. The increase is due primarily to higher interest income on temporary cash investments, and the deferred fuel assets in Texas.

*Interest and Financing Costs* — Interest charges increased by approximately $33 million, or 6.8 percent, for 2007 compared with 2006. The increase is due to higher levels of both short-term and long-term debt and higher interest rates.

Interest charges increased by approximately $24 million, or 5.1 percent, for 2006 compared with 2005. The increase is due to higher levels of both short-term and long-term debt and higher short-term interest rates.

***Income Tax Expense*** — Income taxes for continuing operations increased by $113 million for 2007, compared with 2006. The increase in income tax expense was primarily due to an increase in pretax income (excluding COLI) and $16.1 million of tax expense related to the COLI settlement in 2007 and $29.9 million of tax benefits from the reversal of a regulatory reserve and realized capital loss carry forwards in 2006. The effective tax rate for 2007 was 33.8 percent, compared with 24.2 percent for the same period in 2006. The higher effective tax rate for 2007 was primarily due to the COLI settlement and the lower effective tax rate for 2006 was primarily due to the recognition of a tax benefit relating to the reversal of a regulatory reserve and realized capital loss carry forwards. Without these charges and benefits, the effective tax rate for 2007 and 2006 would have been 30.3 percent and 28.2 percent, respectively.

Income taxes for continuing operations increased by $8 million for 2006, compared with 2005. The effective tax rate for continuing operations was 24.2 percent for 2006, compared with 25.8 percent for 2005. The increase in income tax expense was primarily due to an increase in pretax income, partially offset by $30 million of tax benefits from the reversal of a regulatory reserve and realized capital loss carry forwards. Without these tax benefits the effective tax rate for 2006 would have been 28.2 percent.

See Note 7 to the consolidated financial statements.

## Holding Company and Other Results

The following tables summarize the net income and earnings-per-share contributions of the continuing operations of Xcel Energy's nonregulated businesses and holding company results:

| | Contribution to Xcel Energy's earnings | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Millions of Dollars) | | |
| Eloigne | $ 2.6 | $ 4.6 | $ 6.2 |
| Financing costs — holding company | (71.9) | (66.1) | (52.7) |
| Holding company, taxes and other results | 9.2 | 24.2 | 6.2 |
| Total holding company and other loss — continuing operations | $(60.1) | $(37.3) | $(40.3) |

| | Contribution to Xcel Energy's earnings per share | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Eloigne | $ — | $ 0.01 | $ 0.01 |
| Financing costs and preferred dividends — holding company | (0.15) | (0.12) | (0.09) |
| Holding company, taxes and other results | 0.03 | 0.05 | 0.01 |
| Total holding company and other loss per share — continuing operations | $(0.12) | $(0.06) | $(0.07) |

***Financing Costs and Preferred Dividends*** — Holding company and other results include interest expense and the earnings-per-share impact of preferred dividends, which are incurred at the Xcel Energy and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

The earnings-per-share impact of financing costs and preferred dividends for 2007, 2006 and 2005 included above reflects dilutive securities, as discussed further in Note 8 to the consolidated financial statements. The impact of the dilutive securities, if converted, is a reduction of interest expense resulting in an increase in net income of approximately $10 million in 2007; $15 million in 2006; and $14 million in 2005.

## Statement of Operations Analysis — Discontinued Operations (Net of Tax)

A summary of the various components of discontinued operations is as follows for the years ended Dec. 31:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| **Income (loss) in millions** | | | |
| Cheyenne | $ — | $ 3.0 | $ 0.2 |
| Regulated utility segments — income | — | 3.0 | 0.2 |
| NRG | 0.4 | (0.5) | 16.1 |
| Xcel Energy International | 2.4 | (0.5) | 0.1 |
| e prime | — | 0.1 | (0.1) |
| Seren | (2.9) | 2.1 | 1.8 |
| Utility Engineering Corp. / Quixx Corp. | 1.3 | (0.7) | (4.4) |
| Other | 0.2 | (0.4) | 0.2 |
| Nonregulated/other — income | 1.4 | 0.1 | 13.7 |
| Total income from discontinued operations | $ 1.4 | $ 3.1 | $ 13.9 |
| **Income (loss) per share** | | | |
| Cheyenne | $ — | $0.01 | $ — |
| Regulated utility segments — income per share | — | 0.01 | — |
| NRG | — | — | 0.04 |
| Xcel Energy International | 0.01 | — | — |
| e prime | — | — | — |
| Seren | (0.01) | — | — |
| Utility Engineering, Corp. / Quixx Corp. | — | — | (0.01) |
| Other | — | — | — |
| Nonregulated/other — income per share | — | — | 0.03 |
| Total income per share from discontinued operations | $ — | $0.01 | $ 0.03 |

## Regulated Utility Results — Discontinued Operations

In January 2004, Xcel Energy agreed to sell Cheyenne. Consequently, Xcel Energy reported Cheyenne results as a component of discontinued operations for all periods presented. The sale was completed in January 2005 and resulted in an after-tax loss of approximately $13 million, or 3 cents per share, which was accrued in December 2004. In 2006, the Cheyenne basis study was updated resulting in the recognition of $2.3 million in tax benefits. This plus other Cheyenne related tax benefits totaled $3.3 million or 1 cent per share.

## Other and Nonregulated Results — Discontinued Operations

In April 2005, Zachry Group, Inc. (Zachry) acquired all of the outstanding shares of UE, a nonregulated subsidiary. The majority of Quixx Corp., including Borger Energy Associates and Quixx Power Services, Inc., was sold in October 2006 to affiliates of Energy Investors Funds.

In November 2005, Xcel Energy sold Seren's California assets to WaveDivision Holdings, LLC. In January 2006, Xcel Energy sold Seren's Minnesota assets to Charter Communications.

***Tax Benefits Related to Investment in NRG*** — Xcel Energy has recognized cumulative tax benefits related to the divestiture of NRG of approximately $1.1 billion. Since these tax benefits are related to Xcel Energy's investment in discontinued NRG operations, they are reported primarily in discontinued operations.

Based on current forecasts of taxable income and tax liabilities, Xcel Energy expects to realize approximately $1.1 billion of savings from these tax benefits through a refund of taxes paid in prior years and reduced taxes payable in future years due to net operating loss carryforwards. Xcel Energy used $630 million of these deferred tax benefits through 2006, an additional $90 million in 2007, and expects to use approximately $110 million in 2008. The remainder of the tax benefit carry forward is expected to be used over subsequent years.

## Factors Affecting Results of Continuing 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 natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including the following:

***General Economic Conditions***

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of a future economic slowdown, fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material adverse impact to its results of operations, future growth or ability to raise capital resulting from a general slowdown in future economic growth or a significant increase in interest rates.

***Sales Growth***

In addition to the impact of weather, customer sales levels in Xcel Energy's utility businesses can vary with economic conditions, energy prices, customer usage patterns and other factors. Weather-normalized sales growth for retail electric utility customers was 1.7 percent in 2007, and 1.8 percent in 2006. Weather-normalized sales growth for firm natural gas utility customers was approximately 0.8 percent in 2007, and (2.8) percent in 2006. Weather-normalized sales for 2008 are projected to grow between 1.8 percent and 2.2 percent for retail electric utility customers and 0.0 percent to 1.0 percent for retail natural gas utility customers.

***Fuel Supply and Costs***

*Coal Deliverability* — Xcel Energy's operating utilities have varying dependence on coal-fired generation. Coal-fired generation comprises between 54 percent and 80 percent of the total annual generation. Approximately 86 percent of the annual coal requirements are supplied from the Powder River Basin in Wyoming.

***Pension Plan Costs and Assumptions***

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which includes changes in interest rates and market returns. Changes in the related net pension and post-retirement benefits costs may occur in the future due to changes in assumptions. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

***Regulation***

*PUHCA 2005* — The Energy Act significantly changed many federal statutes. The FERC was given authority to review the books and records of holding companies and their nonutility subsidiaries, authority to review service company accounting and cost allocations, and more authority over the merger and acquisition of public utilities. State commissions have similar authority to review the books and records of holding companies and their nonutility subsidiaries.

*Customer Rate Regulation* — The FERC and various state regulatory commissions regulate Xcel Energy's utility subsidiaries. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing energy market and general economic conditions.

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 general 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 new investments, sales growth, conservation and DSM efforts and the cost of capital. In addition, the return on equity authorized is set by regulatory commissions in rate proceedings.

*Wholesale Energy Market Regulation* — In 2005, a Day 2 wholesale energy market operated by MISO was implemented to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. MISO now centrally issues bills and payments for many costs formerly incurred directly by NSP-Minnesota and NSP-Wisconsin. In September 2007, MISO proposed to modify the Day 2 market to establish a regional ASM effective in June 2008. The ASM is intended to provide further efficiencies in generation dispatch by allowing for regional regulation response and contingency reserve services through a bid-based market mechanism co-optimized with the Day 2 energy market. NSP-Minnesota and NSP-Wisconsin expect to recover MISO charges through either base rates or various recovery mechanisms. See Note 13 to the consolidated financial statements for further discussion.

*Capital Expenditure Regulation* — Xcel Energy's utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC and MPUC approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, and increased transmission. These rate riders are expected to provide significant cash flows to enable recovery of costs incurred on a timely basis. For wholesale electric transmission services, Xcel Energy has, consistent with FERC policy, implemented or proposed to establish formula rates for each of the utility subsidiaries that will provide annual rate increases as transmission investments increase in a manner similar to the rate riders.

***Environmental Matters***

Environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and waste, 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, higher operating expenses and capital expenditures for environmental compliance.

In addition to nuclear decommissioning and spent nuclear fuel disposal expenses, costs charged to operating expenses for environmental monitoring and disposal of hazardous materials and waste were approximately:

- $173 million in 2007;
- $152 million in 2006; and
- $147 million in 2005.

Xcel Energy expects to expense an average of approximately $201 million per year from 2008 through 2012 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. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $438.6 million in 2007;
- $571.2 million in 2006; and
- $327.7 million in 2005.

Xcel Energy expects to incur approximately $455 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2008, and approximately $269 million of related expenditures from 2009 through 2012. Included in these amounts are expenditures to reduce emissions of generating plants in Minnesota and Colorado.

- Approximately $101 million and $14 million of these expenditures, respectively, are related to modifications to reduce the emissions of NSP-Minnesota's generating plants pursuant to the MERP.
- Expected expenditures related to environmental modifications on Comanche Units 1 and 2 are approximately $156 million in 2008 and $38 million from 2009 through 2012.
- The remaining expected capital expenditures relate to various other environmental projects.
- In addition, NSP-Minnesota has proposed a $1.1 billion upgrade at the Sherco coal-fired power plant. The project will increase capacity and reduce emissions. The MPUC is expected to rule on the project in 2008. If approved, construction would start in late 2008 and be completed in 2012.

See Note 15 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Generating facilities throughout the Xcel Energy territory are subject to state-only mercury reduction requirements. In Minnesota mercury emissions from A.S. King and Sherburne County generating facilities will be regulated by the Minnesota Mercury Legislation, and in Colorado, seven units are subject to a mercury emissions rule passed by the Colorado Air Quality Control Commission. These facilities, as well as other generating units, were also subject to regulation under the federal CAMR; however, the D.C. Circuit Court of Appeals vacated this rule on Feb. 8, 2008.

The EPA requires states to develop implementation plans to comply with the BART/Regional Haze Rules by December 2007. At this time, MPCA is not requiring any BART specific controls that go beyond controls required for CAIR compliance. In response to the BART regulations promulgated by the Colorado Air Quality Control Commission, PSCo submitted its BART alternatives analysis, which had been approved by the CAPCD, as well as the Colorado Air Quality Control Commission during a public hearing in December 2007. CAPCD's BART determinations and corresponding provisions of the regional haze state implementation plan will be submitted to the EPA for approval in 2008. The TCEQ has determined that compliance with CAIR is a substitute for BART for NOx and $SO_2$.

In January, NSP-Minnesota made a filing to the MPUC concerning an emissions reduction project at the Sherco generating facility. The improvement project would include generating capacity upgrades for all three units; additional $SO_2$ emission reductions on Units 1 and 2 to improve mercury emission controls; and the installation of additional NOx controls.

***Impact of Nonregulated Investments***

In the past, Xcel Energy's investments in nonregulated operations had a significant impact on its results of operations. As a result of the divestiture of NRG and other nonregulated operations, Xcel Energy does not expect that its investments in nonregulated operations to have a significant impact on its results in the future.

***Inflation***

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

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of 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 could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most critical 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 potential likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been discussed with the Audit Committee of the Xcel Energy Board of Directors.

### Regulatory Accounting

Xcel Energy is a holding company with rate-regulated subsidiaries that are subject to the FASB "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). SFAS No. 71 provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates could be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of current and future cash flows. Regulatory assets represent incurred or accrued costs that have been deferred because they are probable of future recovery from customers. Regulatory liabilities represent incurred or accrued credits that have been deferred because they will be returned to customers in future rates. In other businesses or industries, regulatory assets would be charged to expense and regulatory liabilities would be recorded as income. As of Dec. 31, 2007 and 2006, Xcel Energy has recorded regulatory assets of approximately \$1.1 billion and \$1.2 billion and regulatory liabilities of approximately \$1.4 billion and \$1.4 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current earnings. However, there are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets. In addition, deregulation would be a change that occurs over time, due to legal processes and procedures, which could moderate the impact to Xcel Energy's consolidated financial statements.

See Note 17 for additional details on regulatory assets and liabilities.

### Nuclear Decommissioning

NSP-Minnesota owns nuclear generation facilities and regulations require NSP-Minnesota to decommission its nuclear power plants after each facility is taken out of service. Xcel Energy records future plant removal obligations as a liability at fair value. This liability will be increased over time by applying the interest method of accretion to the liability. Due to regulation, depreciation expense is recorded to match the recovery of future cost of decommissioning, or retirement, of its nuclear generating plants. This recovery is calculated using an annuity approach designed to provide for full rate recovery of the future decommissioning costs.

Amounts recorded for nuclear AROs, in excess of decommissioning expense and investment returns, both realized and unrealized, cumulatively are deferred through the establishment of a regulatory asset for future recovery pursuant to SFAS No. 71.

A portion of the rates charged to customers is deposited into an external trust fund, during the facilities' operating lives, in order to provide for this obligation. The fair value of external nuclear decommissioning trust fund investments are estimated based on quoted market prices for those or similar investments. Realized investment returns from these investments and recovery to date is used by regulators when determining future decommissioning recovery.

NSP-Minnesota conducts periodic decommissioning cost studies to estimate the costs that will be incurred to decommission the facilities. The costs are initially presented in amounts prior to inflation adjustments and then inflated to future periods using decommissioning specific cost inflators. Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through 2050 assuming the prompt dismantlement method. The following key assumptions have a significant effect on these estimates:

- Escalation Rate — The MPUC determines the escalation rate based on various presumptions surrounded by the fact that associated costs will escalate at a certain rate over time. The most recent decommissioning study, completed in 2005, set the escalation rate at 3.61 percent. An escalation rate for the cost of disposing of nuclear fuel waste was set at 6.0 percent. Over the short-term, these rates can differ from the set rates and accrual estimates can be significantly affected by small changes in assumed escalation rates.
- Life Extension — Currently, decommissioning recovery periods end in 2020 for Monticello and in 2013 and 2014 for Prairie Island's two facilities. Changes made to decommissioning cost estimates, the escalation rate and the earnings rate can be amplified by these short end-of-license life periods. With the recent re-licensing of Monticello and the preparation for re-licensing Prairie Island, any change in license life could have a material effect on the accrual. Under FASB Statement No. 143 — Accounting for AROs (SFAS No. 143), current calculations have assumed full life extension, which brings the regulatory recovery period up to 2020. These adjustments reduced the depreciation expense of NSP-Minnesota by approximately $41 million for the period ended Dec.31, 2007. In addition, the lengthening of the remaining life for the Monticello nuclear plant decreased the related ARO and related regulatory asset by $121 million in the third quarter of 2007. Prairie Island anticipates filing a similar application in 2008, with final state and federal approvals expected in 2010.
- Cost Estimate With Spent Fuel Disposal — Federal regulations require the DOE to provide a permanent repository for the storage of spent nuclear fuel. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The spent fuel storage assumptions have a significant influence on the decommissioning cost estimate. The manner in which spent nuclear fuel is managed and the assumptions used to develop cost estimates of decommissioning programs have a dramatic impact, which in turn can have a corresponding impact on the resulting accrual.

The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The total obligation for decommissioning currently is expected to be funded 100 percent by a portion of the rates charged to customers, as approved by the MPUC. Decommissioning expense recoveries are based upon the same assumptions and methodologies as the fair value obligations are recorded. In addition to these assumptions discussed previously, assumptions related to future earnings of the nuclear decommissioning fund are utilized by the MPUC in determining the recovery of decommissioning costs. Through utilization of the annuity approach, an assumed rate of return on funding is calculated which provides the earnings rate. With a long period of decommissioning and a funding period over the operating lives of each facility, the ability of the fund to sustain the required payments after inflation while assuring the appropriate investment structure is critical in obtaining the best benefit in the accrual. Currently, an assumption that the external funds will earn a return of 5.4 percent, after tax is utilized when setting recovery by the MPUC.

Significant uncertainties exist in estimating the future cost of decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned treatment of spent fuel. Materially different results could be obtained if different assumptions were utilized. Currently, our estimates of future decommissioning costs and the obligation to retire the plants have a significant impact to our financial position. The amounts recorded for AROs and regulatory assets for unrecovered costs are $1,315.1 million and $39.9 million as of December 31, 2007. If different cost estimates, shorter life assumptions or different cost escalation rates were utilized, this ARO and the unrecovered balance in regulatory assets could change materially. If future earnings on the decommissioning fund are lower than that estimated currently, future decommissioning recoveries would need to increase. The significance to our results of operations is reduced due to the fact that we record decommissioning expense based upon recovery amounts approved by our regulators. This treatment reduces the volatility of expense over time. The difference between regulatory funding (including both depreciation expense less returns from the investments fund) and amounts recorded under SFAS No. 143 are deferred as a regulatory asset.

## Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of effective tax rates.

Effective tax rates (ETR) are also highly impacted by assumptions. ETR calculations are revised every quarter based on best available year-end tax assumptions (income levels, deductions, credits, etc.) by legal entity; adjusted in the following year after returns are filed, with the tax accrual estimates being trued-up to the actual amounts claimed on the tax returns; and further adjusted after examinations by taxing authorities have been completed.

In accordance with the interim reporting rules under APB 28, a tax expense or benefit is recorded every quarter to eliminate the difference in continuing operations tax expense computed based on the actual year-to-date ETR and the forecasted annual ETR.

Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109 (FIN 48), has impacted the income tax accrual process in that the new accounting rule requires that only tax benefits that meet the "more likely than not" recognition threshold can be recognized or continue to be recognized. The change in the unrecognized tax benefits need to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimate of range of reasonably possible changes. At any period end, and as new developments occur, management will use prudent business judgment to unrecognize appropriate amounts of tax benefits. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline. As required, Xcel Energy adopted FIN 48 as of Jan. 1, 2007 and the initial derecognition amounts were reported as a cumulative effect of a change in accounting principle. The cumulative effect of the change, which was reported as an adjustment to the beginning balance of retained earnings, was not material.

As disputes with the IRS and state tax authorities are resolved over time, we may need to adjust our unrecognized tax benefits and interest accruals to the updated estimates needed to satisfy tax and interest obligations for the related issues. These adjustments may be favorable or unfavorable, increasing or decreasing earnings.

See Note 7 for further details regarding income taxes.

## Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. Note 10 to the consolidated financial statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs have been increasing in recent years, but are expected to decrease over the next several years, due to higher-than-expected investment returns experienced in recent years, as well as voluntary company contributions. While investment returns exceeded the assumed level of 8.75 percent in 2006 and 2005 and 9.0 percent in 2004, investment returns in 2007, 2003 and 2002 were below the assumed level of 8.75, 9.25 and 9.5 percent respectively, and discount rates have increased to 6.00 percent used in 2007. Xcel Energy continually reviews its pension assumptions and, in 2008, expects to maintain the investment return assumption at 8.75 percent and to increase the discount rate assumption to 6.25 percent.

The investment gains or losses resulting from the difference between the expected pension returns assumed on asset levels and actual returns earned are deferred in the year the difference arises and recognized over the subsequent five-year period. This gain or loss recognition occurs by using a five-year, moving-average value of pension assets to measure expected asset returns in the cost-determination process, and by amortizing deferred investment gains or losses over the subsequent five-year period. Based on current assumptions and the recognition of past investment gains and losses over the next five years, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes in continuing operations will decrease from an expense, of $11.4 million in 2007 to income of $6.0 million in 2008 and income of $8.4 million in 2009.

Xcel Energy bases its discount rate assumption on benchmark interest rates from Moody's. At Dec. 31, 2007, the annualized Moody's Baa index rate was 6.56 percent, and the Aaa index rate was 5.41 percent. Accordingly, Xcel Energy increased the discount rate to 6.25 percent as of Dec. 31, 2007. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2008 pension cost determinations. At Dec. 31, 2006, the annualized Moody's Baa index rate was 6.35 percent and the Aaa index rate was 5.46 percent. The corresponding pension discount rate was 6.00 percent.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Xcel Energy projects that no cash funding would be required for 2007 or 2008. However, Xcel Energy expects to make voluntary contributions in 2007 and 2008 to maintain a level of funded status that allows for future funding flexibility and reduces cash flow volatility under the Pension Protection Act. These expected contributions are summarized in Note 10 to the consolidated financial statements. These amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future. However, all pension costs are expected to be recoverable in rates.

If Xcel Energy were to use alternative assumptions for pension cost determinations, a one-percent change would result in the following impact on the estimates recognized by Xcel Energy:

| | Pension Costs | |
|---|---|---|
| | +1% | −1% |
| | (in millions) | |
| **Effect on Dec. 31, 2007 Benefit Obligations:** | | |
| Rate of Return | $(19.8) | $19.8 |
| Discount Rate | (4.9) | 6.8 |

Effective Dec. 31, 2007, Xcel Energy reduced its initial medical trend assumption from 9.0 percent to 8.0 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is six years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan. See Note 10 for additional discussion of Xcel Energy's benefit plans.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2007.

For a discussion of significant accounting policies, see Note 1 to the consolidated financial statements.

## Pending Accounting Changes

***Fair Value Measurements (SFAS No. 157)*** — In September 2006, the FASB issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS No. 157 on its consolidated financial statements and does not expect the impact of implementation to be material.

***The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115 (SFAS No. 159)*** — In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after Nov. 15, 2007. Xcel Energy does not expect the implementation of SFAS No. 159 to have a material impact on its consolidated financial statements.

***Business Combinations (SFAS No. 141 (revised 2007))*** — In December 2007, the FASB issued SFAS No. 141R, which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. Xcel Energy is evaluating the impact of SFAS No. 141R on its consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

***Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51(SFAS No. 160)*** — In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently. This statement is effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy is evaluating the impact of SFAS No. 160 on its consolidated financial statements.

## Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. These risks, as applicable to Xcel Energy and its subsidiaries, are discussed in further detail later.

***Commodity Price Risk*** — Xcel Energy's utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk-management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

***Short-Term Wholesale and Commodity Trading Risk*** — Xcel Energy's utility subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity and energy and other energy-related instruments. Xcel Energy's risk-management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

The fair value of the commodity trading contracts at Dec. 31, 2007, were as follows:

| | (Millions of Dollars) |
|---|---|
| Fair value of trading contracts outstanding at Jan. 1, 2007 | $ (1.2) |
| Contracts realized or settled during the year | (14.8) |
| Fair value of trading contract additions and changes during the year | 22.3 |
| Fair value of trading contracts outstanding at Dec. 31, 2007 | $ 6.3 |

At Dec. 31, 2007, the fair values by source for the commodity trading net asset or liability balances were as follows:

| | Futures/Forwards | | | | | |
|---|---|---|---|---|---|---|
| | Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Futures/ Forwards Fair Fair Value |
| | | (Thousands of Dollars) | | | | |
| NSP-Minnesota | 1 | $(2,499) | $ — | $— | $— | $(2,499) |
| | 2 | 3,769 | 980 | — | — | 4,749 |
| PSCo | 1 | (657) | — | — | — | (657) |
| | 2 | 3,893 | 701 | — | — | 4,594 |
| SPS* | 1 | 63 | — | — | — | 63 |
| | 2 | 163 | 38 | — | — | 201 |
| Total Futures/Forwards Fair Value | | $ 4,732 | $1,719 | $— | $— | $ 6,451 |

| | Source of Fair Value | Options: Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Options Fair Value |
|---|---|---|---|---|---|---|
| | | (Thousands of Dollars) | | | | |
| NSP-Minnesota | 2 | $(139) | $— | $— | $— | $(139) |
| SPS* | 2 | 3 | — | — | — | 3 |
| Total Options Fair Value | | $(136) | $— | $— | $— | $(136) |

(1) — Prices actively quoted or based on actively quoted prices.

(2) — Prices based on models and other valuation methods. These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the model.

* — SPS conducts an inconsequential amount of commodity trading. Margins from commodity trading activity are partially redistributed to SPS, NSP-Minnesota, and PSCo, pursuant to the JOA approved by the FERC. As a result of the JOA, margins received pursuant to the JOA are reflected as part of the fair values by source for the commodity trading net asset or liability balances.

Normal purchases and sales transactions, as defined by SFAS No. 133, hedge transactions and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations.

At Dec. 31, 2007, a 10-percent increase in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.1 million, whereas a 10-percent decrease would decrease pretax income from continuing operations by approximately $0.1 million.

Xcel Energy's short-term wholesale and commodity trading operations 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 VaR. VaR expresses the potential change 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, delta half-gamma approach for non-linear instruments and a three-day holding period for both electricity and natural gas.

VaR is calculated on a consolidated basis. The VaRs for the commodity trading operations were:

| | Year ended Dec. 31, 2007 | During 2007: Average | High | Low |
|---|---|---|---|---|
| | | (Millions of Dollars) | | |
| Commodity trading[a] | $0.26 | $0.47 | $1.45 | $0.09 |

| | Year ended Dec. 31, 2006 | During 2006: Average | High | Low |
|---|---|---|---|---|
| | | (Millions of Dollars) | | |
| Commodity trading[a] | $0.49 | $1.32 | $2.60 | $0.39 |

(a) Comprises transactions for NSP-Minnesota, PSCo and SPS.

***Interest Rate Risk*** — Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Dec. 31, 2007, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $12.7 million. See Note 12 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries' interest rate swaps.

Xcel Energy and its subsidiaries also maintain trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At Dec. 31, 2007, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore fluctuations in equity prices or interest rates do not have an impact on earnings.

*Credit Risk* — Xcel Energy and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from the nonperformance by a counterparty of its contractual obligations. 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 counterparties. Xcel Energy employs additional credit risk control mechanisms, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions 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.

At Dec. 31, 2007, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $19.6 million, while a decrease of 10 percent would have resulted in a decrease of $12.0 million.

## Liquidity and Capital Resources

## Cash Flows

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Millions of Dollars) | |
| **Cash provided by operating activities** | | | |
| Continuing operations | $1,500 | $1,729 | $1,131 |
| Discontinued operations | 72 | 195 | 53 |
| Total | $1,572 | $1,924 | $1,184 |

Cash provided by operating activities for continuing operations decreased $229 million during 2007. The decrease was primarily due to changes in working capital activity primarily the timing of accounts receivables and unbilled revenues. The decrease in cash provided by operations was partially offset by the collection of recoverable purchased natural gas and electric energy costs. Cash provided by operating activities for discontinued operations decreased $123 million during 2007, largely due to the sale of related assets.

Cash provided by operating activities for continuing operations increased $598 million during 2006. The increase is primarily due to the timing of working capital activity. Specifically, the collection of receivables and the collection of recoverable purchased natural gas and electric energy costs increased in 2006. The increase in cash provided by operations was partially offset by the timing of cash expenditures for accounts payable. Cash provided by operating activities for discontinued operations increased $142 million during 2006, largely due to the realization of deferred tax assets related to NRG.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Millions of Dollars) | |
| **Cash provided by (used in) investing activities** | | | |
| Continuing operations | $(2,023) | $(1,601) | $(1,362) |
| Discontinued operations | — | 51 | 136 |
| Total | $(2,023) | $(1,550) | $(1,226) |

Cash used in investing activities for continuing operations increased $422 million during 2007, primarily due to increased utility capital expenditures, partially offset by the cash obtained from the consolidation of NMC and the sale of certain investments in the nuclear decommissioning trust fund. No cash was provided by investing activities for discontinued operations.

Cash used in investing activities for continuing operations increased $239 million during 2006, primarily due to increased utility capital expenditures, partially offset by a decrease in restricted cash and proceeds from the sale of assets. Cash provided by investing activities for discontinued operations decreased $85 million during 2006, primarily due to the receipt of proceeds from the sale of Cheyenne and Seren in 2005.

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Millions of Dollars) | |
| **Cash provided by (used in) financing activities** | | | |
| Continuing operations | $483 | $(422) | $111 |
| Total | $483 | $(422) | $111 |

Cash flow from financing activities related to continuing operations increased $905 million during 2007 due to increased short-term borrowings as well as a decrease in the repayments of long-term debt.

Cash flow from financing activities related to continuing operations decreased $533 million during 2006 due to increased net repayments of short-term borrowings in 2006 compared to 2005.

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

## Capital Requirements

***Utility Capital Expenditures and Long-Term Debt Obligations*** — The estimated cost of the capital expenditure programs of Xcel Energy and its subsidiaries, excluding discontinued operations, and other capital requirements for the years 2008 through 2011 are shown in the tables below.

| By Segment | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| Electric utility | $1,880 | $1,375 | $1,465 | $1,775 |
| Natural gas utility | 145 | 160 | 160 | 150 |
| Common utility and other | 75 | 65 | 75 | 75 |
| Total capital expenditures | 2,100 | 1,600 | 1,700 | 2,000 |
| Debt maturities | 638 | 558 | 542 | 52 |
| Total capital requirements | $2,738 | $2,158 | $2,242 | $2,052 |

| By Utility Subsidiary | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| NSP-Minnesota | $1,005 | $ 805 | $ 910 | $1,190 |
| NSP-Wisconsin | 100 | 90 | 80 | 80 |
| PSCo | 825 | 505 | 530 | 590 |
| SPS | 170 | 200 | 180 | 140 |
| Total | $2,100 | $1,600 | $1,700 | $2,000 |

| By Project | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|
| Base and other capital expenditures | $ 1,095 | $ 1,135 | $ 1,170 | $ 1,170 |
| MERP | 170 | 25 | 10 | — |
| Comanche 3 | 330 | 60 | 10 | — |
| Minnesota wind/CapX 2020 transmission | 40 | 65 | 115 | 300 |
| Sherco capacity increases | 5 | 20 | 75 | 230 |
| Minnesota wind generation | 135 | — | — | — |
| Nuclear capacity increases and life extension | 75 | 120 | 180 | 200 |
| Nuclear fuel | 150 | 150 | 140 | 100 |
| Fort St. Vrain CT | 100 | 25 | — | — |
| Total committed capital expenditures | $ 2,100 | $ 1,600 | $ 1,700 | $ 2,000 |
| Potential projects | 0-100 | 200-400 | 200-400 | 200-500 |
| Range | $2,100-2,200 | $1,800-2,000 | $1,900-2,100 | $2,200-2,500 |

Many of the states in which Xcel Energy operates have enacted renewable portfolio standards, which would require significant increases in investment in renewable generation and transmission. Xcel Energy would generally be able to meet these standards by either purchasing renewable power from an independent party or by owning the assets. Therefore, these standards may present Xcel Energy with the opportunity to increase its investment in wind generation and transmission assets. As a result, Xcel Energy's capital expenditure forecast, as detailed above, may increase due to the potential increased investments for renewable generation and transmission assets. The other potential projects included in the table above represent wind generation, natural gas generation and transmission projects that may result from the Colorado and Minnesota resource plans that were filed in the fourth quarter of 2007. These potential projects will require commission approval.

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, regulatory decisions and approvals, 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 restructuring requirements, compliance with future environmental requirements and renewable portfolio standards to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

***Contractual Obligations and Other Commitments*** — Xcel Energy has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2007. See additional discussion in the consolidated statements of capitalization and Notes 4, 5, and 15 to the consolidated financial statements.

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | Less than 1 Year | 1 to 3 Years | 4 to 5 Years | After 5 Years |
| | | | (Thousands of Dollars) | | |
| Long-term debt, principal and interest payments | $12,599,312 | $1,065,530 | $1,849,818 | $1,760,489 | $ 7,923,475 |
| Capital lease obligations | 85,951 | 6,139 | 11,794 | 11,139 | 56,879 |
| Operating leases[(a)], [(b)] | 1,439,346 | 104,557 | 200,000 | 161,743 | 973,046 |
| Unconditional purchase obligations | 12,047,364 | 2,448,155 | 3,321,234 | 2,247,977 | 4,029,998 |
| Other long-term obligations — WYCO investment | 121,000 | 108,000 | 13,000 | — | — |
| Other long-term obligations[(c)] | 165,847 | 31,589 | 42,775 | 38,964 | 52,519 |
| Payments to vendors in process | 145,059 | 145,059 | — | — | — |
| Short-term debt | 1,088,560 | 1,088,560 | — | — | — |
| Total contractual cash obligations[(d)] | $27,692,439 | $4,997,589 | $5,438,621 | $4,220,312 | $13,035,917 |

(a) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2006, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $176.8 million. In addition, at the end of the equipment leases' terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value or equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(b) Included in operating lease payments are $76.6 million, $151.7 million, $124.5 million and $916.6 million, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories, respectively, pertaining to five purchase power agreements that were accounted for as operating leases.

(c) Included in other long-term obligations are tax, penalties and interest related to unrecognized tax benefits recorded according to FIN 48.

(d) Xcel Energy and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. Certain contractual purchase obligations are adjusted based on indices. The effects of price changes are mitigated through cost-of-energy adjustment mechanisms.

(e) Xcel Energy also has outstanding authority under contracts and blanket purchase orders to purchase up to approximately $1.6 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

Xcel Energy has also executed five additional purchase power agreements that are conditional upon achievement of certain conditions, including becoming operational. Estimated payments under these conditional obligations are $52.8 million, $165.7 million, $177.9 million and $1.7 billion, respectively, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories.

***Common Stock Dividends*** — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows and other factors, and will be evaluated by the Xcel Energy board of directors. Xcel Energy's objective is to increase the annual dividend in the range of 2 percent to 4 percent per year. Xcel Energy's dividend policy balances:

- Projected cash generation from utility operations;
- Projected capital investment in the utility businesses;
- A reasonable rate of return on shareholder investment; and
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places certain limits on the ability of public utilities within a holding company system to declare dividends.

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The cash to pay dividends to Xcel Energy shareholders is primarily derived from dividends received from its utility subsidiaries. The utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory commissions to be paid to the holding company. The limitation is imposed through equity ratio limitations that range from 30 percent to 60 percent. Some utility subsidiaries must comply with bond indenture covenants or restrictions under credit agreements for debt to total capitalization ratios.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to common stock plus surplus, divided by the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's capitalization ratio at Dec. 31, 2007, was 85 percent. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends.

## Capital Sources

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, preferred securities and hybrid securities to maintain desired capitalization ratios.

*Short-Term Funding Sources* — Historically, Xcel Energy has used a number of sources to fulfill short-term funding needs, including operating cash flow, 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 construction expenditures, working capital and dividend payments.

As of Feb. 15, 2008, Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

| | Facility | Drawn* | Available | Cash | Liquidity | Maturity |
|---|---|---|---|---|---|---|
| | | | (Million of Dollars) | | | |
| NSP-Minnesota | $ 500 | $323.4 | $ 176.6 | $ 8.7 | $ 185.3 | December 2011 |
| PSCo | 700 | 184.2 | 515.8 | 125.9 | 641.7 | December 2011 |
| SPS | 250 | 103.0 | 147.0 | 0.3 | 147.3 | December 2011 |
| Xcel Energy — holding company | 800 | 179.8 | 620.2 | 4.6 | 624.8 | December 2011 |
| Total | $2,250 | $790.4 | $1,459.6 | $139.5 | $1,599.1 | |

* Includes outstanding commercial paper and letters of credit.

Operating cash flow as a source of short-term funding is affected by such operating factors as weather; regulatory requirements, including rate recovery of costs; environmental regulation compliance; changes in the trends for energy prices; supply and operational uncertainties and other changes in working capital, all of which are difficult to predict. See further discussion of such factors under Statement of Operations Analysis.

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. For additional information on Xcel Energy's short-term borrowing arrangements, see Note 4 to the consolidated financial statements. Access to reasonably priced capital markets is dependent in part on credit agency reviews and ratings. The following ratings reflect the views of Moody's, Standard & Poor'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 agency. As of Feb. 15, 2008, the following represents the credit ratings assigned to various Xcel Energy companies:

| Company | Credit Type | Moody's | Standard & Poor's | Fitch |
|---|---|---|---|---|
| Xcel Energy | Senior Unsecured Debt | Baa1 | BBB | BBB+ |
| Xcel Energy | Commercial Paper | P-2 | A-2 | F2 |
| NSP-Minnesota | Senior Unsecured Debt | A3 | BBB | A |
| NSP-Minnesota | Senior Secured Debt | A2 | A | A+ |
| NSP-Minnesota | Commercial Paper | P-2 | A-2 | F1 |
| NSP-Wisconsin | Senior Unsecured Debt | A3 | BBB+ | A |
| NSP-Wisconsin | Senior Secured Debt | A2 | A | A+ |
| PSCo | Senior Unsecured Debt | Baa1 | BBB | A- |
| PSCo | Senior Secured Debt | A3 | A | A |
| PSCo | Commercial Paper | P-2 | A-2 | F2 |
| SPS | Senior Unsecured Debt | Baa1 | BBB+ | BBB+ |
| SPS | Commercial Paper | P-2 | A-2 | F2 |

Note: Moody's highest credit rating for debt is Aaa and lowest investment grade rating is Baa3. Both Standard & Poor's and Fitch's highest credit rating for debt are AAA and lowest investment grade rating is BBB-. Moody's prime ratings for commercial paper range from P-1 to P-3. Standard & Poor's ratings for commercial paper range from A-1 to A-3. Fitch's ratings for commercial paper range from F1 to F3.

In the event of a downgrade of its credit ratings to below investment grade, Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy all or a part of its exposures under guarantees outstanding. See a list of guarantees at Note 13 to the consolidated financial statements. Xcel Energy has no explicit credit rating requirements in its debt agreements.

***Money Pool*** — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates.

The utility money pool arrangement does not allow loans from the utility subsidiaries to the holding company. NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions.

The borrowings or loans outstanding at Dec. 31, 2007, and the SEC approved short-term borrowing limits from the money pool are as follows (millions):

| | Borrowings (Loans) | Total Borrowing Limits |
|---|---|---|
| NSP-Minnesota | $ (95.1) | $250 |
| PSCo | 100.6 | 250 |
| SPS | (5.5) | 100 |

***Registration Statements*** — Xcel Energy's articles of incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2007, Xcel Energy had approximately 429 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, 2007, Xcel Energy had approximately 1 million shares of preferred stock outstanding. Xcel Energy and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy has an effective automatic shelf registration statement that does not contain a limit on issuance capacity; however, Xcel Energy's ability to issue securities is limited by authority granted by the Board of Directors, which authority currently authorizes the issuance of up to an additional $1.1 billion of debt securities.
- NSP-Minnesota has $1.5 billion of debt securities available under its current effective registration statement.
- PSCo has approximately $850 million of debt securities available under its currently effective registration statement.

## Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments primarily through internally generated funds. Xcel Energy expects to convert the $57.5 million principal balance of its Senior Convertible Notes due Nov. 21, 2008, to common equity by the maturity date of the notes. Xcel Energy plans to issue commercial paper to meet short-term working capital requirements.

During 2008, Xcel Energy plans to issue debt securities at several of its operating companies. These financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors. Current debt financing plans include the following:

- NSP-Minnesota plans to issue between $400-$500 million of long-term senior debt securities to refinance outstanding commercial paper, to fund utility capital expenditures and to provide funds for general corporate purposes. NSP-Minnesota plans to issue commercial paper to meet short-term working capital requirements, including funding for inter-company loans to NSP-Wisconsin.
- PSCo plans to issue between $500-$600 million of long-term senior debt securities to refinance a $300 million long-term debt maturity, to refinance outstanding commercial paper, to fund utility capital expenditures and to provide funds for general corporate purposes. PSCo plans to issue commercial paper to meet short-term working capital requirements.
- NSP-Wisconsin plans to issue up to $250 million of long-term senior debt securities to refinance an $80 million long-term debt maturity, to repay outstanding short-term debt, to fund utility capital expenditures and to provide funds for general corporate purposes. NSP-Wisconsin plans to issue inter-company notes to NSP-Minnesota to meet short-term working capital requirements.

## Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

## Earnings Guidance

Xcel Energy's 2008 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

| | 2008 Diluted Earnings Per Share Range |
|---|---|
| Utility operations | $1.61 - $1.71 |
| Holding company financing costs and other | (0.16) |
| **Xcel Energy Continuing Operations** | $1.45 - $1.55 |

***Key Assumptions for 2008:***

- Normal weather patterns are experienced during the year.
- Regulatory approval of various riders associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, which are expected to increase revenue by approximately $60 million to $70 million over the projected 2007 levels.
- Reasonable regulatory outcomes in the New Mexico electric rate case, Texas electric rate case and North Dakota electric rate case.
- No material incremental accruals related to the SPS regulatory proceedings.
- Weather-adjusted retail electric utility sales grow by approximately 1.8 percent to 2.2 percent.
- Weather-adjusted retail firm natural gas sales grow by approximately 0.0 percent to 1.0 percent.
- Short-term wholesale and commodity trading margins are within a range of $20 million to $30 million.
- Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $45 million to $55 million over 2007 levels. We expect regulatory recovery of approximately $11 million of the increase in capacity costs at SPS. Capacity costs at PSCo are recovered under the PCCA.
- Utility operating and maintenance expenses increase between 2 percent and 3 percent.
- Depreciation expense is projected to increase approximately $60 million to $70 million over 2007 levels.
- Interest expense increases approximately $25 million to $35 million over 2007 levels.
- Allowance for funds used during construction-equity increases approximately $35 million to $45 million over 2007 levels.
- An effective tax rate for continuing operations of approximately 32 percent to 35 percent.
- Average common stock and equivalents for diluted earnings per share calculations of approximately 438 million shares.

## Item 7A — Quantitative and Qualitative Disclosures About Market Risk

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

## Item 8 — Financial Statements and Supplementary Data

See Item 15(a)-1 in Part IV for index of financial statements included herein.

See Note 19 of Notes to consolidated financial statements for summarized quarterly financial data.

## Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy's internal control system was designed to provide reasonable assurance to the company's management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy management assessed the effectiveness of the company's internal control over financial reporting as of Dec. 31, 2007. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we believe that, as of Dec. 31, 2007, the company's internal control over financial reporting is effective based on those criteria.

Xcel Energy's independent auditors have issued an audit report on the company's internal control over financial reporting. Their report appears on the following page.

/S/ RICHARD C. KELLY

Richard C. Kelly
*Chairman, President and Chief Executive Officer*
February 20, 2008

/S/ BENJAMIN G.S. FOWKE III

Benjamin G.S. Fowke III
*Vice President and Chief Financial Officer*
February 20, 2008

# Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (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 provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 7 to the consolidated financial statements, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109," as of January 1, 2007. As discussed in Note 10 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," as of December 31, 2006.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2008

# Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2007 of the Company and our report dated February 20, 2008 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's adoption of new accounting standards.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2008

# XCEL ENERGY INC. AND SUBSIDIARIES
## Consolidated Statements of Income
*(thousands of dollars, except per share data)*

| | Year ended Dec. 31 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Operating revenues** | | | |
| Electric utility | $ 7,847,992 | $7,608,018 | $7,243,637 |
| Natural gas utility | 2,111,732 | 2,155,999 | 2,307,385 |
| Other | 74,446 | 76,287 | 74,455 |
| Total operating revenues | 10,034,170 | 9,840,304 | 9,625,477 |
| **Operating expenses** | | | |
| Electric fuel and purchased power — utility | 4,136,994 | 4,103,055 | 3,922,163 |
| Cost of natural gas sold and transported — utility | 1,547,622 | 1,644,716 | 1,823,123 |
| Cost of sales — other | 24,370 | 24,388 | 24,676 |
| Other operating and maintenance expenses | 1,869,215 | 1,773,526 | 1,707,665 |
| Depreciation and amortization | 827,173 | 821,898 | 767,321 |
| Taxes (other than income taxes) | 277,723 | 295,727 | 287,810 |
| Total operating expenses | 8,683,097 | 8,663,310 | 8,532,758 |
| **Operating income** | 1,351,073 | 1,176,994 | 1,092,719 |
| Interest and other income, net | 10,948 | 4,085 | 857 |
| Allowance for funds used during construction — equity | 37,207 | 25,045 | 21,627 |
| **Interest charges and financing costs** | | | |
| Interest charges — includes other financing costs of $21,410, $24,187 and $25,829, respectively | 520,037 | 486,967 | 463,370 |
| Interest and penalties related to COLI settlement | 43,401 | — | — |
| Allowance for funds used during construction — debt | (34,593) | (30,935) | (20,744) |
| Total interest charges and financing costs | 528,845 | 456,032 | 442,626 |
| Income from continuing operations before income taxes | 870,383 | 750,092 | 672,577 |
| Income taxes | 294,484 | 181,411 | 173,539 |
| **Income from continuing operations** | 575,899 | 568,681 | 499,038 |
| Income from discontinued operations — net of tax | 1,449 | 3,073 | 13,934 |
| **Net income** | 577,348 | 571,754 | 512,972 |
| Dividend requirements on preferred stock | 4,241 | 4,241 | 4,241 |
| Earnings available to common shareholders | $ 573,107 | $ 567,513 | $ 508,731 |

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| **Weighted average common shares outstanding** | | | |
| Basic | 416,139 | 405,689 | 402,330 |
| Diluted | 433,131 | 429,605 | 425,671 |
| **Earnings per share — basic** | | | |
| Income from continuing operations | $ 1.38 | $ 1.39 | $ 1.23 |
| Income from discontinued operations | — | 0.01 | 0.03 |
| Earnings per share | $ 1.38 | $ 1.40 | $ 1.26 |
| **Earnings per share — diluted** | | | |
| Income from continuing operations | $ 1.35 | $ 1.35 | $ 1.20 |
| Income from discontinued operations | — | 0.01 | 0.03 |
| Earnings per share | $ 1.35 | $ 1.36 | $ 1.23 |
| **Cash dividends declared per common share** | $ 0.91 | $ 0.88 | $ 0.85 |

# XCEL ENERGY INC. AND SUBSIDIARIES

## Consolidated Statements of Cash Flows

*(thousands of dollars)*

| | Year ended Dec. 31 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Operating activities** | | | |
| Net income | $ 577,348 | $ 571,754 | $ 512,972 |
| Remove income from discontinued operations | (1,449) | (3,073) | (13,934) |
| Adjustments to reconcile net income to cash provided by operating activities: | | | |
| Depreciation and amortization | 855,897 | 857,129 | 782,074 |
| Nuclear fuel amortization | 53,453 | 47,531 | 45,330 |
| Deferred income taxes | 265,277 | (59,843) | 205,058 |
| Amortization of investment tax credits | (8,680) | (9,806) | (11,620) |
| Allowance for equity funds used during construction | (37,207) | (25,045) | (21,627) |
| Undistributed equity in earnings of unconsolidated affiliates | (1,900) | (2,775) | (712) |
| Gain or write down of assets sold or held for sale | — | (6,189) | 2,887 |
| Share-based compensation expense | 22,871 | 40,384 | 27,598 |
| Net realized and unrealized hedging and derivative transactions | 6,463 | (27,219) | 9,715 |
| Changes in operating assets and liabilities (net of effects of consolidation of NMC) | | | |
| Accounts receivable | (79,373) | 176,732 | (250,305) |
| Accrued unbilled revenues | (217,659) | 99,716 | (178,585) |
| Inventories | (25,464) | 28,967 | (94,605) |
| Recoverable purchased natural gas and electric energy costs | 185,185 | 136,470 | (130,442) |
| Other current assets | (9,922) | (1,831) | 2,002 |
| Accounts payable | (10,018) | (105,707) | 281,430 |
| Net regulatory assets and liabilities | 27,428 | (34,211) | (20,433) |
| Other current liabilities | 52,771 | 97,216 | 15,927 |
| Change in other noncurrent assets | (56,053) | 4,956 | (39,995) |
| Change in other noncurrent liabilities | (99,098) | (56,415) | 7,699 |
| Operating cash flows provided by discontinued operations | 72,346 | 195,255 | 53,283 |
| Net cash provided by operating activities | 1,572,216 | 1,923,996 | 1,183,717 |
| **Investing activities** | | | |
| Utility capital/construction expenditures | (2,095,721) | (1,626,000) | (1,304,468) |
| Allowance for equity funds used during construction | 37,207 | 25,045 | 21,627 |
| Purchase of investments in external decommissioning fund | (712,462) | (1,288,103) | (576,001) |
| Proceeds from the sale of investments in external decommissioning fund | 669,070 | 1,240,034 | 494,529 |
| Nonregulated capital expenditures and asset acquisitions | (1,136) | (1,620) | (6,976) |
| Proceeds from sale of assets | — | 24,670 | 11,228 |
| Investment in WYCO | 29,659 | — | — |
| Change in restricted cash | (9,190) | 11,813 | (6,226) |
| Cash obtained from consolidation of NMC | 38,950 | — | — |
| Other investments | 20,832 | 13,535 | 5,075 |
| Investing cash flows provided by discontinued operations | — | 50,516 | 135,577 |
| Net cash used in investing activities | (2,022,791) | (1,550,110) | (1,225,635) |
| **Financing activities** | | | |
| Proceeds from (repayment of) short-term borrowings — net | 462,260 | (119,820) | 433,820 |
| Proceeds from issuance of long-term debt | 1,162,272 | 1,326,180 | 2,529,408 |
| Repayment of long-term debt, including reacquisition premiums | (768,146) | (1,285,584) | (2,517,698) |
| Proceeds from issuance of common stock | 10,539 | 16,275 | 9,085 |
| Dividends paid | (378,892) | (358,746) | (343,092) |
| Early participation payment on debt exchange | (4,859) | — | — |
| Financing cash flows used in discontinued operations | — | — | (200) |
| Net cash (used in) provided by financing activities | 483,174 | (421,695) | 111,323 |
| Net increase (decrease) in cash and cash equivalents | 32,599 | (47,809) | 69,405 |
| Net increase (decrease) in cash and cash equivalents — discontinued operations | (18,937) | 13,071 | (20,570) |
| Cash and cash equivalents at beginning of year | 37,458 | 72,196 | 23,361 |
| Cash and cash equivalents at end of year | $ 51,120 | $ 37,458 | $ 72,196 |
| Supplemental disclosure of cash flow information | | | |
| Cash paid for interest (net of amounts capitalized) | $ 469,142 | $ 427,683 | $ 417,016 |
| Cash paid for income taxes (net of refunds received) | 6,467 | (13,329) | 10,625 |
| Supplemental disclosure of non-cash investing transactions: | | | |
| Property, plant and equipment additions in accounts payable | $ 39,681 | $ 54,102 | $ 42,526 |
| Supplemental disclosure of non-cash financing transactions: | | | |
| Issuance of common stock for reinvested dividends and 401(k) plans | $ 53,105 | $ 56,194 | $ 43,882 |
| Issuance of common stock for senior convertible notes | 229,623 | — | — |

# XCEL ENERGY INC. AND SUBSIDIARIES

## Consolidated Balance Sheets

*(thousands of dollars)*

| | Dec. 31 2007 | Dec. 31 2006 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 51,120 | $ 37,458 |
| Accounts receivable, net of allowance for bad debts of $49,401 and $36,689, respectively | 951,580 | 833,293 |
| Accrued unbilled revenues | 731,959 | 514,300 |
| Materials and supplies inventories | 152,770 | 158,721 |
| Fuel inventories | 142,764 | 95,651 |
| Natural gas inventories | 236,076 | 251,818 |
| Recoverable purchased natural gas and electric energy costs | 73,415 | 258,600 |
| Derivative instruments valuation | 94,554 | 101,562 |
| Prepayments and other | 244,134 | 205,743 |
| Current assets held for sale and related to discontinued operations | 128,821 | 177,040 |
| Total current assets | 2,807,193 | 2,634,186 |
| Property, plant and equipment, at cost: | | |
| Electric utility plant | 20,313,313 | 19,367,671 |
| Natural gas utility plant | 2,946,455 | 2,846,435 |
| Common utility and other property | 1,475,325 | 1,439,020 |
| Construction work in progress | 1,810,664 | 1,425,484 |
| Total property, plant and equipment | 26,545,757 | 25,078,610 |
| Less accumulated depreciation | (10,049,927) | (9,670,104) |
| Nuclear fuel, net of accumulated amortization of $1,291,370 and $1,237,917, respectively | 179,859 | 140,152 |
| Net property, plant and equipment | 16,675,689 | 15,548,658 |
| Other assets: | | |
| Nuclear decommissioning fund and other investments | 1,372,098 | 1,279,573 |
| Regulatory assets | 1,115,443 | 1,189,145 |
| Derivative instruments valuation | 383,861 | 437,520 |
| Prepaid pension asset | 568,055 | 586,712 |
| Other | 142,078 | 135,746 |
| Noncurrent assets held for sale and related to discontinued operations | 120,310 | 146,806 |
| Total other assets | 3,701,845 | 3,775,502 |
| Total assets | $23,184,727 | $21,958,346 |
| **Liabilities and Equity** | | |
| Current liabilities: | | |
| Current portion of long-term debt | $ 637,535 | $ 336,411 |
| Short-term debt | 1,088,560 | 626,300 |
| Accounts payable | 1,079,345 | 1,101,270 |
| Taxes accrued | 240,443 | 252,384 |
| Dividends payable | 99,682 | 91,685 |
| Derivative instruments valuation | 58,811 | 83,944 |
| Other | 419,209 | 347,809 |
| Current liabilities held for sale and related to discontinued operations | 17,539 | 25,478 |
| Total current liabilities | 3,641,124 | 2,865,281 |
| Deferred credits and other liabilities: | | |
| Deferred income taxes | 2,553,526 | 2,256,599 |
| Deferred investment tax credits | 112,914 | 121,594 |
| Regulatory liabilities | 1,389,987 | 1,364,657 |
| Asset retirement obligations | 1,315,144 | 1,361,951 |
| Derivative instruments valuation | 384,419 | 483,077 |
| Customer advances | 305,239 | 302,168 |
| Pension and employee benefit obligations | 576,426 | 704,913 |
| Other | 137,422 | 121,193 |
| Noncurrent liabilities held for sale and related to discontinued operations | 20,384 | 5,473 |
| Total deferred credits and other liabilities | 6,795,461 | 6,721,625 |
| Commitments and contingent liabilities | | |
| Capitalization: | | |
| Long-term debt | 6,342,160 | 6,449,638 |
| Preferred stockholders' equity | 104,980 | 104,980 |
| Common stockholders' equity | 6,301,002 | 5,816,822 |
| Total liabilities and equity | $23,184,727 | $21,958,346 |

# XCEL ENERGY INC. AND SUBSIDIARIES
## Consolidated Statements of Common Stockholders' Equity and Comprehensive Income
*(thousands)*

| | Common Stock Issued: Shares | Common Stock Issued: Par Value | Common Stock Issued: Additional Paid In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Common Stockholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at Dec. 31, 2004** | 400,462 | $1,001,155 | $3,911,056 | $ 396,641 | $(105,934) | $5,202,918 |
| Net income | | | | 512,972 | | 512,972 |
| Minimum pension liability adjustment, net of tax of $(10,717) | | | | | (17,271) | (17,271) |
| Net derivative instrument fair value changes during the period, net of tax of $(5,137) | | | | | (8,919) | (8,919) |
| Unrealized gain — marketable securities, net of tax of $41 | | | | | 63 | 63 |
| Comprehensive income for 2005 | | | | | | 486,845 |
| Dividends declared: | | | | | | |
| Cumulative preferred stock | | | | (4,241) | | (4,241) |
| Common stock | | | | (343,234) | | (343,234) |
| Issuances of common stock | 2,925 | 7,313 | 45,654 | | | 52,967 |
| **Balance at Dec. 31, 2005** | 403,387 | $1,008,468 | $3,956,710 | $ 562,138 | $(132,061) | $5,395,255 |
| Net income | | | | 571,754 | | 571,754 |
| Minimum pension liability adjustment, net of tax of $19,498 | | | | | 31,957 | 31,957 |
| Net derivative instrument fair value changes during the period, net of tax of $6,297 | | | | | 11,000 | 11,000 |
| Unrealized loss — marketable securities, net of tax of $(18) | | | | | (26) | (26) |
| Comprehensive income for 2006 | | | | | | 614,685 |
| SFAS No. 158 adoption, net of tax of $42,265 | | | | | 72,804 | 72,804 |
| Dividends declared: | | | | | | |
| Cumulative preferred stock | | | | (4,241) | | (4,241) |
| Common stock | | | | (358,402) | | (358,402) |
| Issuances of common stock | 3,910 | 9,774 | 58,998 | | | 68,772 |
| Share-based compensation | | | 27,949 | | | 27,949 |
| **Balance at Dec. 31, 2006** | 407,297 | $1,018,242 | $4,043,657 | $ 771,249 | $ (16,326) | $5,816,822 |
| FIN 48 adoption | | | | 2,207 | | 2,207 |
| Net income | | | | 577,348 | | 577,348 |
| Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(1,872) | | | | | (1,855) | (1,855) |
| Net derivative instrument fair value changes during the period, net of tax of $(4,704) | | | | | (3,611) | (3,611) |
| Unrealized gain — marketable securities, net of tax of $(2) | | | | | 4 | 4 |
| Comprehensive income for 2007 | | | | | | 571,886 |
| Dividends declared: | | | | | | |
| Cumulative preferred stock | | | | (4,241) | | (4,241) |
| Common stock | | | | (382,647) | | (382,647) |
| Issuances of common stock | 21,486 | 53,715 | 219,802 | | | 273,517 |
| Share-based compensation | | | 23,458 | | | 23,458 |
| **Balance at Dec. 31, 2007** | 428,783 | $1,071,957 | $4,286,917 | $ 963,916 | $ (21,788) | $6,301,002 |

# Consolidated Statements of Capitalization

*(thousands of dollars)*

| | Dec. 31 2007 | Dec. 31 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| **Long-Term Debt** | | |
| **NSP-Minnesota** | | |
| First Mortgage Bonds, Series due: | | |
| Aug. 1, 2010, 4.75% | $ 175,000 | $ 175,000 |
| Aug. 28, 2012, 8% | 450,000 | 450,000 |
| March 1, 2019, 8.5%[(b)] | 27,900 | 27,900 |
| Sept. 1, 2019, 8.5%[(b)] | 100,000 | 100,000 |
| July 1, 2025, 7.125% | 250,000 | 250,000 |
| March 1, 2028, 6.5% | 150,000 | 150,000 |
| April 1, 2030, 8.5%[(b)] | 69,000 | 69,000 |
| July 15, 2035, 5.25% | 250,000 | 250,000 |
| June 1, 2036, 6.25% | 400,000 | 400,000 |
| July 1, 2037, 6.2% | 350,000 | — |
| Senior Notes, due Aug. 1, 2009, 6.875% | 250,000 | 250,000 |
| Retail Notes, due July 1, 2042, 8% | — | 185,000 |
| Other | 31 | 89 |
| Unamortized discount-net | (8,822) | (7,761) |
| Total | 2,463,109 | 2,299,228 |
| Less current maturities | 31 | 40 |
| Total NSP-Minnesota long-term debt | $2,463,078 | $2,299,188 |
| **PSCo** | | |
| First Mortgage Bonds, Series due: | | |
| Oct. 1, 2008, 4.375% | $ 300,000 | $ 300,000 |
| Oct. 1, 2012, 7.875% | 600,000 | 600,000 |
| March 1, 2013, 4.875% | 250,000 | 250,000 |
| April 1, 2014, 5.5% | 275,000 | 275,000 |
| Sept. 1, 2017, 4.375%[(b)] | 129,500 | 129,500 |
| Jan. 1, 2019, 5.1%[(b)] | 48,750 | 48,750 |
| Sept. 1, 2037, 6.25% | 350,000 | — |
| Unsecured Senior A Notes, due July 15, 2009, 6.875% | 200,000 | 200,000 |
| Secured Medium-Term Notes, due March 5, 2007, 7.11% | — | 100,000 |
| Capital lease obligations, 11.2% due in installments through 2028 | 44,868 | 46,247 |
| Unamortized discount | (5,029) | (2,840) |
| Total | 2,193,089 | 1,946,657 |
| Less current maturities | 301,445 | 101,379 |
| Total PSCo long-term debt | $1,891,644 | $1,845,278 |
| **SPS** | | |
| Unsecured Senior A Notes, due March 1, 2009, 6.2% | $ 100,000 | $ 100,000 |
| Unsecured Senior C and D Notes, due Oct. 1, 2033, 6% | 100,000 | 100,000 |
| Unsecured Senior E Notes, due Oct. 1, 2016, 5.6% | 200,000 | 200,000 |
| Unsecured Senior F Notes, due Oct. 1, 2036, 6% | 250,000 | 250,000 |
| Pollution control obligations, securing pollution control revenue bonds, due: | | |
| July 1, 2011, 5.2% | 44,500 | 44,500 |
| July 1, 2016, 3.43% at Dec. 31, 2007, and 3.95% at Dec. 31, 2006 | 25,000 | 25,000 |
| Sept. 1, 2016, 5.75% | 57,300 | 57,300 |
| Unamortized discount | (2,767) | (2,897) |
| Total | 774,033 | 773,903 |
| Less current maturities | — | — |
| Total SPS long-term debt | $ 774,033 | $ 773,903 |

# XCEL ENERGY INC. AND SUBSIDIARIES

## Consolidated Statements of Capitalization — (Continued)

*(thousands of dollars)*

| | Dec. 31 2007 | Dec. 31 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| **Long-Term Debt — continued** | | |
| **NSP-Wisconsin** | | |
| First Mortgage Bonds, Series due: | | |
| Oct. 1, 2018, 5.25% | $ 150,000 | $ 150,000 |
| Dec. 1, 2026, 7.375% | 65,000 | 65,000 |
| Senior Notes due, Oct. 1, 2008, 7.64% | 80,000 | 80,000 |
| City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6%[(a)] | 18,600 | 18,600 |
| Fort McCoy System Acquisition, due Oct. 15, 2030, 7% | 760 | 794 |
| Unamortized discount | (786) | (852) |
| Total | 313,574 | 313,542 |
| Less current maturities | 80,034 | 34 |
| Total NSP-Wisconsin long-term debt | $ 233,540 | $ 313,508 |
| **Other Subsidiaries** | | |
| Various Eloigne Co. Affordable Housing Project Notes, due 2008-2045, 0% — 10.25% | $ 86,273 | $ 90,910 |
| Other | 2,094 | 2,122 |
| Total | 88,367 | 93,032 |
| Less current maturities | 6,116 | 4,958 |
| Total other subsidiaries long-term debt | $ 82,251 | $ 88,074 |
| **Xcel Energy Inc.** | | |
| Unsecured senior notes, Series due: | | |
| July 1, 2008, 3.4% | $ 195,000 | $ 195,000 |
| Dec. 1, 2010, 7% | 358,636 | 600,000 |
| April 1, 2017, 5.613% | 253,979 | — |
| July 1, 2036, 6.5% | 300,000 | 300,000 |
| Convertible notes, Series due: | | |
| Nov. 21, 2007, 7.5% | — | 230,000 |
| Nov. 21, 2008, 7.5% | 57,500 | 57,500 |
| Fair value hedge, carrying value adjustment | (2,591) | (17,786) |
| Unamortized discount | (15,001) | (5,027) |
| Total | 1,147,523 | 1,359,687 |
| Less current maturities | 249,909 | 230,000 |
| Total Xcel Energy Inc. debt | $ 897,614 | $1,129,687 |
| Total long-term debt | $6,342,160 | $6,449,638 |
| **Preferred Stockholders' Equity** | | |
| Preferred Stock — authorized 7,000,000 shares of $100 par value; outstanding shares: 2007: 1,049,800; 2006: 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 preferred stockholders' equity | $ 104,980 | $ 104,980 |
| **Common Stockholders' Equity** | | |
| Common stock — authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2007: 428,782,700; 2006: 407,296,907 | $1,071,957 | $1,018,242 |
| Additional paid in capital | 4,286,917 | 4,043,657 |
| Retained earnings | 963,916 | 771,249 |
| Accumulated other comprehensive loss | (21,788) | (16,326) |
| Total common stockholders' equity | $6,301,002 | $5,816,822 |

(a) Resource recovery financing

(b) Pollution control financing

## 1. Summary of Significant Accounting Policies

***Business and System of Accounts*** — Xcel Energy's 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. 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 respects.

***Principles of Consolidation*** — In 2007, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 8 states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WGI, an interstate natural gas pipeline, and WYCO, a natural gas pipeline and storage company in Colorado, these companies comprise our continuing regulated utility operations.

Xcel Energy's nonregulated subsidiary in continuing operations is Eloigne (investments in rental housing projects that qualify for low-income housing reported tax credits). 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 in the past had several other subsidiaries, which were sold or divested. For more information, see Note 3 to the consolidated financial statements.

During 2007, Xcel Energy became the sole remaining partner of NMC. This is the result of two of the remaining three partners leaving NMC during 2007. As a result, both companies were required to pay an exit fee and surrender their equity interest in NMC. Xcel Energy owns 100 percent of the equity and has a controlling interest.

Xcel Energy uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects for which it does not have a controlling financial interest. Under this method, a proportionate share of pretax income is recorded as equity earnings from investments in affiliates. In the consolidation process, all intercompany transactions and balances are eliminated. Xcel Energy has investments in several plants and transmission facilities jointly owned with other utilities. These projects are accounted for on a proportionate consolidation basis, consistent with industry practice. See Note 6 to the consolidated financial statements.

***Revenue Recognition*** — Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based on the reading of their meter, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated.

Xcel Energy's utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of purchased natural gas and electric fuel and purchased energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, for any difference between the total amount collected under the clauses and the recoverable costs incurred. Where applicable under governing state regulatory commission rate orders, fuel costs over-recoveries (the excess of fuel revenue billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. In addition, Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees. A summary of significant rate-adjustment mechanisms follows:

- NSP-Minnesota's rates include a cost-of-fuel-and-purchased-energy and a cost-of-gas recovery mechanism allowing recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively.

  The electric cost-of-fuel-and-purchased-energy mechanism also provides a sharing among shareholders and customers of certain margins on short-term wholesale sales and commodity trading.
- NSP-Wisconsin's rates include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. In Wisconsin, requests can be made for recovery of those electric costs

prospectively through the rate review process, which normally occurs every two years and an interim fuel-cost hearing process.

- PSCo generally recovers all prudently incurred electric fuel and purchased energy costs through the ECA. The ECA is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. Effective January 2007, the ECA was modified to include an incentive adjustment to encourage efficient operation of base load coal plants and encourage cost reductions through purchases of economical short-term energy. The total incentive payment to PSCo in any calendar year will not exceed $11.25 million. The ECA mechanism is revised quarterly and interest accrues monthly on the average deferred balance. The ECA will expire at the earlier of rates taking effect after Comanche 3 is placed in service or Dec. 31, 2010.
- In Texas, SPS recovers fuel and purchased energy costs through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric rates. The Texas retail fuel factors change each November and May based on the projected costs of natural gas. In New Mexico and at the FERC, SPS has a monthly fuel and purchased power cost-recovery factor.
- NSP-Minnesota rates in Minnesota include monthly adjustments for recovery of conservation and energy-management program costs, which are reviewed annually. NSP-Minnesota is allowed to recover certain costs associated with new transmission facilities to deliver renewable energy resources through a rate rider.
- PSCo's rates include annual adjustments for the recovery of conservation and energy-management program costs, which are reviewed annually. PSCo is allowed to recover certain costs associated with renewable energy resources through a specific retail rate rider. In January 2008, a new recovery mechanism for transmission commenced. The TCA permits PSCo to recover costs associated with investment in transmission facilities made after March 2007 through a rate rider.
- NSP-Minnesota, NSP-Wisconsin, PSCo and SPS sell firm power and energy in wholesale markets, which are regulated by the FERC. Certain of these rates include monthly wholesale fuel cost-recovery mechanisms.

***Commodity Trading Operations —*** All applicable gains and losses related to commodity trading activities, whether or not settled physically, are shown on a net basis in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities: (SFAS 133). In addition, commodity trading results include the impact of all margin-sharing mechanisms.

***Types of and Accounting for Derivative Instruments —*** Xcel Energy and its subsidiaries use derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by SFAS 133 are recorded on the consolidated balance sheets at fair value as derivative instruments valuation. The classification of the fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. The adjustment to fair value of derivative instruments not designated in a qualifying hedging relationship is reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations.

Gains or losses on hedging transactions for the sales of energy or energy-related products are primarily recorded as a component of revenue; hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; hedging transactions for natural gas purchased for resale are recorded as a component of natural gas costs; and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility.

*Cash Flow and Fair Value Hedges —* Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The designation of a cash flow hedge permits the classification of fair value to be recorded within Other Comprehensive Income (OCI), to the extent effective. The designation of a fair value hedge permits a derivative instrument's gains or losses to offset the related results of the hedged item in the consolidated statements of income.

SFAS 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting. Xcel Energy and its subsidiaries formally document all hedging relationships in accordance with SFAS 133. The documentation includes, among other factors, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. In addition, at inception and on a quarterly basis, Xcel Energy and its subsidiaries formally assess whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in OCI, until earnings are affected by the hedged transaction. Xcel Energy discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. To test the effectiveness of hedges, a hypothetical hedge is used to mirror all the critical terms of the underlying debt and the dollar offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. The fair value of interest rate derivatives is determined through counterparty valuations, internal valuations and broker quotes. Gains and losses related to discontinued hedges that were previously accumulated in OCI will remain in OCI until the underlying contract is reflected in earnings; unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in OCI are immediately recognized in current earnings.

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge is 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 gains or losses of the derivative instrument to offset, in the same period, the gains and losses of the hedged item. The ineffective portion of a derivative instrument's change in fair value is recognized in current earnings.

*Normal Purchases and Normal Sales* — Xcel Energy's utility subsidiaries enter into contracts for the purchase and sale of commodities for use in their business operations. SFAS 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from SFAS 133 as normal purchases or normal sales.

Xcel Energy evaluates all of its contracts when such contracts are entered to determine if they are derivatives and, if so, if they qualify to meet the normal designation requirements under SFAS 133. None of the contracts entered into within the commodity trading operations qualify for a normal designation.

For further discussion of Xcel Energy's risk management and derivative activities, see Note 12 to the consolidated financial statements.

***Property, Plant and 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 is charged to accumulated depreciation and amortization. Removal costs associated with regulatory obligations are recorded as regulatory liabilities. 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. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use.

Xcel Energy records depreciation expense related to its plant by using the straight-line method over the plant's useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.2 percent for the years ended Dec. 31, 2007, 2006 and 2005.

***AFDC*** — AFDC 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.

Generally, AFDC costs are recovered from customers as the related property is depreciated. However, in some cases our commissions have approved a more current recovery of cost associated with large capital projects, resulting in a lower recognition of AFDC.

***Decommissioning*** — Xcel Energy accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The 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. The fair value of external nuclear decommissioning fund investments are determined based on quoted market prices for those or similar investments. Unrealized gains or losses are included with regulatory assets on the consolidated balance sheets. For more information on nuclear decommissioning, see Note 16 to the consolidated financial statements.

***Nuclear Fuel Expense*** — Nuclear fuel expense, which is recorded as the nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFDC), as well as future disposal costs of spent nuclear fuel, costs associated with the end-of-life fuel segments and fees assessed by the DOE for NSP-Minnesota's portion of the cost of decommissioning the DOE's fuel-enrichment facility.

***Environmental Costs*** — Environmental costs are recorded on an undiscounted basis when it is probable Xcel Energy is liable for the costs and the liability can reasonably be estimated. Costs may be deferred as a regulatory asset if it is probable that the costs will be recovered from customers in future rates. Otherwise, the costs are expensed. If an environmental expense is related to facilities currently in use, such as emission-control equipment, the cost is capitalized and depreciated over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

Estimated remediation costs, excluding inflationary increases, are recorded. The estimates are based on experience, an assessment of the current situation and the technology currently available for use in the remediation. The recorded costs are regularly adjusted as estimates are revised and as remediation proceeds. If several designated responsible parties exist, only Xcel Energy's expected share of the cost is estimated and recorded. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

***Legal Costs*** — Litigation accruals are recorded when it is probable Xcel Energy is liable for the costs and the liability can be reasonably estimated. External legal fees related to settlements are expensed as incurred.

***Income Taxes*** — Xcel Energy accounts for income taxes using the asset and liability method under FAS 109, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax asset will not be realized. In making such a determination, all available positive and negative evidence, including scheduled reversals of deferred tax liabilities, projected future taxable income, tax planning strategies and recent financial operations, is considered.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 7 to the consolidated financial statements.

In July 2006, the FASB issued FIN 48, which prescribes how a company should recognize, measure, present and disclose uncertain tax positions that such company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the "more likely than not" recognition threshold be recognized or continue to be recognized on its effective date. As required, Xcel Energy adopted FIN 48 as of Jan. 1, 2007 and the initial derecognition amounts were reported as a cumulative effect of a change in accounting principle. The cumulative effect of the change, which was reported as an adjustment to the beginning balance of retained earnings, was not material. Following implementation, the ongoing recognition of changes in measurement of uncertain tax positions will be reflected as a component of income tax expense.

Xcel Energy reports interest and penalties related to income taxes within the interest charges section in the consolidated statements of income.

Xcel Energy and its domestic subsidiaries file consolidated federal income tax returns. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns.

Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. The holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company.

***Use of Estimates*** — In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, AROs, decommissioning, tax provisions, uncollectible amounts, environmental costs, unbilled revenues, jurisdictional fuel and energy cost allocations and actuarially determined benefit costs. The recorded estimates are revised when better information becomes available or when actual amounts can be determined. Those revisions can affect operating results. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate.

***Cash and Cash Equivalents*** — Xcel Energy considers investments in certain instruments, including commercial paper and money market funds, with a remaining maturity of three months or less at the time of purchase to be cash equivalents.

***Restricted Cash*** — At Dec. 31, 2007 and 2006, Xcel Energy had restricted cash of $33 million and $24 million, respectively. The restricted cash balances primarily represent margin deposits held in conjunction with electric futures trading contracts. These balances are presented as a component of other long-term assets on the consolidated balance sheets.

***Inventory*** — All inventory is recorded at average cost.

***Regulatory Accounting*** — Our regulated utility subsidiaries account for certain income and expense items in accordance with SFAS No. 71 — "Accounting for the Effects of Certain Types of Regulation." Under SFAS No. 71:

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment.

If restructuring or other changes in the regulatory environment occur, our regulated utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's results of operations in the period the write-offs are recorded. See more discussion of regulatory assets and liabilities at Note 17 to the consolidated financial statements.

***Deferred Financing Costs*** — Other assets included deferred financing costs, net of amortization, of approximately $48 million and $47 million at Dec. 31, 2007 and 2006, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt. The premiums and costs associated with modified debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines. If the company extinguishes the debt, all unamortized balances shall be expensed at the time of the redemption.

***Accounts Receivable and Allowance for Bad Debts*** — Accounts receivable are stated at the actual billed amount net of write-offs and allowance for uncollectibles. Xcel Energy establishes an allowance for uncollectibles based on a reserve policy that reflects its expected exposure to the credit risk of customers.

***Renewable Energy Credits*** — Renewable Energy Credits (RECs) are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. These credits can be bought and sold. RECs are typically used as a form of measurement of compliance to Renewable Portfolio Standards (RPS) enacted by those states that are encouraging construction and consumption of renewable energy, but can also be sold separately from the energy produced. Currently, SPS acquires RECs from the generation or purchase of renewable power.

When RECs are acquired in the course of generation or purchase as a result of meeting the load obligation, they are recorded as inventory at actual cost. REC's acquired for trading purposes are recorded as other investments at actual cost. The cost of RECs that are retired for compliance purposes are recorded as electric fuel and purchased power. The net margin on sales of RECs for trading purposes is recorded as electric utility operating revenues net of any margin sharing requirements. As a result of state regulatory orders, we reduce recoverable fuel costs for the value of certain

RECs and record the cost of RECs to satisfy future compliance requirements that are recoverable in future rates as regulatory assets under the criteria of SFAS No. 71.

***Emission Allowances*** — Emission allowances are recorded at cost, including the annual $SO_2$ and NOx emission allowance entitlement received at no cost from the EPA. Xcel Energy follows the inventory model for all allowances. The sales of allowances are reported in the operating activities section of the consolidated statements of cash flows. The net margin on sales of emission allowances is included in electric utility operating revenues as it is integral to the production process of energy and our revenue optimization strategy for our utility operations.

***Reclassifications*** — Certain amounts in the consolidated statements of cash flows have been reclassified from prior-period presentation. The reclassifications reflect the presentation of unbilled revenues, recoverable purchased natural gas and electric energy costs and regulatory assets and liabilities and share-based compensation expense as separate items rather than components of other assets and other liabilities within net cash provided by operating activities. In addition, activity related to derivative transactions have been combined into net realized and unrealized hedging and derivative transactions. These reclassifications did not affect total net cash provided by (used in) operating, investing or financing activities within the consolidated statements of cash flows.

## 2. Recently Issued Accounting Pronouncements

***Fair Value Measurements (SFAS No. 157)*** — In September 2006, the FASB issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS No. 157 on its consolidated financial statements and does not expect the impact of implementation to be material.

***The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of FASB Statement No. 115 (SFAS No. 159)*** — In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after Nov. 15, 2007, effective Jan. 1, 2008. Xcel Energy adopted SFAS No. 159 and the adoption did not have a material impact on its consolidated financial statements.

***Business Combinations (SFAS No. 141 (revised 2007))*** — In December 2007, the FASB issued SFAS No. 141R, which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity's fiscal year that begins on or after Dec. 15, 2008. Xcel Energy will evaluate the impact of SFAS No. 141R on its consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

***Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB No. 51(SFAS No. 160)*** — In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent's equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently. This statement is effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy is evaluating the impact of SFAS No. 160 on its consolidated financial statements.

## 3. Discontinued Operations

Xcel Energy classified and accounted for certain assets as held for sale at Dec. 31, 2007 and 2006. Assets held for sale are valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, management considered cash flow analyses, bids and offers related to those assets and businesses. Assets held for sale are not depreciated.

Results of operations for divested businesses and the results of businesses held for sale are reported, for all periods presented, as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale in 2007 and 2006 have been reclassified to assets and liabilities held for sale in the consolidated balance sheets. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets associated with temporary differences and NOL and tax credit carryforwards that will be deductible in future years.

## Regulated Utility Subsidiaries

In 2005, Black Hills Corp. purchased all the common stock of Cheyenne, including the assumption of outstanding debt of approximately $25 million, for approximately $90 million, plus a working capital adjustment finalized in 2005. The sale resulted in an after-tax loss of approximately $13 million, or 3 cents per share.

## Nonregulated Subsidiaries

***Utility Engineering*** — In April 2005, Zachry acquired all of the outstanding shares of UE. Xcel Energy recorded an insignificant loss during 2005 as a result of the transaction. The majority of Quixx Corp., including Borger Energy Associates and Quixx Power Services, Inc., was sold in October 2006 to affiliates of Energy Investors Funds.

***Seren*** — In November 2005, Xcel Energy sold Seren's California assets to WaveDivision Holdings, LLC. In January 2006, Xcel Energy sold Seren's Minnesota assets to Charter Communications. An estimated after-tax impairment charge, including disposition costs, of $143 million, or 34 cents per share, was recorded in 2004. Based on the sales agreements entered into in 2005, the estimate was adjusted in 2005 to reflect a total asset impairment of $140 million.

***Xcel Energy International and e prime*** — The exit of all business conducted by Xcel Energy International was completed in 2004. The results of discontinued nonregulated operations in 2004 include the impact of the sale of the Argentina subsidiaries of Xcel Energy International, for a sales price of approximately $31 million. In addition to the sales price, Xcel Energy also received approximately $21 million at the closing of one transaction as redemption of its capital investment. The sales resulted in a gain of approximately $8 million, including the realization of approximately $7 million of income tax benefits realizable upon the sale of the Xcel Energy International assets. The exit of all business conducted by e prime was completed in 2004.

***NRG*** — With NRG's emergence from bankruptcy in December 2003, Xcel Energy divested its ownership interest in NRG. Xcel Energy recognized a $17 million tax benefit related to the divestiture of NRG in 2005. These tax expenses and benefits are reported as discontinued operations.

## Summarized Financial Results of Discontinued Operations

| | Utility Segment | All Other Segment | Total |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| **2007** | | | |
| Operating revenues | $ — | $ 36 | $ 36 |
| Operating income, interest and other income, net | (2) | (1,150) | (1,152) |
| Pretax income from discontinued operations | 2 | 1,186 | 1,188 |
| Income tax benefit | (5) | (256) | (261) |
| Net income from discontinued operations | $ 7 | $ 1,442 | $ 1,449 |
| **2006** | | | |
| Operating revenues | $ — | $ 7,525 | $ 7,525 |
| Operating expense, interest and other income, net | 278 | 9,011 | 9,289 |
| Pretax loss from discontinued operations | (278) | (1,486) | (1,764) |
| Income tax benefit | (3,291) | (1,546) | (4,837) |
| Net income from discontinued operations | $ 3,013 | $ 60 | $ 3,073 |
| **2005** | | | |
| Operating revenues | $ 6,579 | $ 63,206 | $ 69,785 |
| Operating expense, interest and other income, net | 6,131 | 68,669 | 74,800 |
| Pretax income (loss) from discontinued operations | 448 | (5,463) | (5,015) |
| Income tax expense (benefit) | 268 | (19,217) | (18,949) |
| Net income from discontinued operations | $ 180 | $ 13,754 | $ 13,934 |

The major classes of assets and liabilities held for sale and related to discontinued operations as of Dec. 31 are as follows:

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| Cash | $ 6,792 | $ 25,729 |
| Account receivables, net | 913 | 421 |
| Deferred income tax benefits | 118,919 | 144,740 |
| Other current assets | 2,197 | 6,150 |
| Current assets held for sale and related to discontinued operations | 128,821 | 177,040 |
| Net property, plant and equipment | — | 174 |
| Deferred income tax benefits | 97,284 | 144,564 |
| Other noncurrent assets | 23,026 | 2,068 |
| Noncurrent assets held for sale and related to discontinued operations | 120,310 | 146,806 |
| Accounts payable | 1,060 | 1,560 |
| Other current liabilities | 16,479 | 23,918 |
| Current liabilities held for sale and related to discontinued operations | 17,539 | 25,478 |
| Other noncurrent liabilities | 20,384 | 5,473 |
| Noncurrent liabilities held for sale and related to discontinued operations | $ 20,384 | $ 5,473 |

## 4. Short-Term Borrowings

***Commercial Paper*** — At Dec. 31, 2007 and 2006, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $1,088.6 million and $626.3 million, respectively. The weighted average interest rates at Dec. 31, 2007 and 2006 were 5.57 percent and 5.47 percent, respectively.

## 5. Long-Term Debt

*Credit Facilities* — At Dec. 31, 2007, Xcel Energy and its utility subsidiaries had the following committed credit facilities available:

| | Credit Facility | Credit Facility Borrowings | Available* | Term | Maturity |
|---|---|---|---|---|---|
| | | | (Millions of Dollars) | | |
| NSP-Minnesota | $ 500 | $— | $ 152.4 | Five year | December 2011 |
| PSCo | 700 | — | 423.9 | Five year | December 2011 |
| SPS | 250 | — | 120.0 | Five year | December 2011 |
| Xcel Energy — holding company | 800 | — | 446.2 | Five year | December 2011 |
| Total | $2,250 | $— | $1,142.5 | | |

* Net of credit facility borrowings, issued and outstanding letters of credit and commercial paper borrowings

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. Each credit facility has one financial covenant requiring that the debt-to-total-capitalization ratio of each entity be less than or equal to 65 percent with which all were in compliance at Dec. 31, 2007 and 2006. If Xcel Energy or any of its utility subsidiaries do not comply with the covenant, it is deemed an event of default and any outstanding amounts due under the facility can be declared due by the lender. Each credit facility has a cross default provision that provides the borrower will be in default on its borrowings under the facility if any of its subsidiaries, comprising more than 15 percent of the consolidated assets, defaults on any of its indebtedness greater than $50 million. The interest rates under these lines of credit are based on either the agent bank's prime rate or the applicable LIBOR, plus a borrowing margin based on the applicable debt rating.

Xcel Energy has an $800 million, five-year senior unsecured revolving credit facility that matures in December 2011. Xcel Energy has the right to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval.

- At Dec. 31, 2007, Xcel Energy had no direct borrowings on this line of credit, however, the credit facility was used to provide backup for $353.1 million of commercial paper outstanding and $0.7 million of letters of credit.
- At Dec. 31, 2006, Xcel Energy had no direct borrowings on this line of credit, however, the credit facility was used to provide backup for $113.8 million of commercial paper outstanding and $0.7 million of letters of credit.
- At Dec. 31, 2007, $20.1 million letters of credit were outstanding, of which $0.7 million were supported by the Xcel Energy credit facility and are included in the above table.
- At Dec. 31, 2006, $43.8 million letters of credit were outstanding, of which $0.7 million were supported by the Xcel Energy credit facility.

### *Convertible Debt*

Xcel Energy's 2007 and 2008 series convertible senior notes include provisions for conversion into shares of Xcel Energy common stock at a conversion price of $12.33 per share. Conversion is at the option of the holder at any time prior to maturity. In addition, Xcel Energy must make additional payments of interest, referred to as protection payments, on the notes in an amount equal to any portion of regular quarterly per share dividends on common stock that exceeds 18.75 cents per share that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. On May 23, 2007, the board of directors of Xcel Energy voted to raise the quarterly dividend on its common stock from 22.25 cents per share to 23.00 cents per share. Consequently, as of Dec. 31, 2007 and 2006, a total of $2.1 million and $3.1 million in additional interest expense has been recorded, respectively. During the second and fourth quarter of 2007, approximately $126 million and $104 million, respectively, of the Xcel convertible notes due Nov. 21, 2007, were converted to common stock.

### *Long-Term Borrowings*

On June 26, 2007, NSP-Minnesota issued $350 million of 6.20 percent first mortgage bonds, series due July 1, 2037. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper.

On Aug. 1, 2007, NSP-Minnesota redeemed all of its outstanding 8.00 percent Notes, series due 2042, at a redemption price equal to 100 percent of the principal amount of the notes ($25.00), plus accrued and unpaid interest on the notes, if any, to the redemption date. Upon redemption, Xcel Energy recognized approximately $9.3 million in interest expense due to unwinding a fair value interest rate derivative.

On Aug. 15, 2007, PSCo issued $350 million of 6.25 percent first mortgage bonds, series due Sept. 1, 2037. PSCo added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper, including commercial paper incurred to fund the payment at maturity of $100 million of 7.11 percent secured medium-term notes, which matured on March 5, 2007.

On Jan. 16, 2008, Xcel Energy issued $400 million of 7.60 percent junior subordinated notes, series due 2068. Xcel Energy added the net proceeds from the sale of the notes to its general funds and intends to use the proceeds to fund equity investments in one or more of its utility subsidiaries that will be used to repay short-term debt of the subsidiary. The remaining proceeds will be used to repay commercial paper.

All property of NSP-Minnesota and NSP-Wisconsin and the electric property of PSCo are subject to the liens of their first mortgage indentures. In addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

Maturities of long-term debt are:

| | (Millions of Dollars) |
|---|---|
| 2008 | $ 637.5 |
| 2009 | 557.7 |
| 2010 | 541.5 |
| 2011 | 51.5 |
| 2012 | 1,066.3 |

### *Debt Exchange*

On March 30, 2007, Xcel Energy settled an exchange offer for up to $350 million aggregate principal amount of its 7 percent Senior Notes, Series due 2010 (the Old Notes). Xcel Energy accepted approximately $241.4 million aggregate principal amount of its Old Notes in exchange for approximately $254.0 million aggregate principal amount of a new series of 5.613 percent senior notes due April 1, 2017 (the New Notes). The $12.6 million non-cash increase in the aggregate principal amount was a result of financing the premium associated with the exchange. In addition, Xcel Energy paid the following amounts in cash: (i) approximately $4.8 million to certain investors as an early participation payment for Old Notes validly tendered prior to 5:00 p.m., New York City time, on March 13, 2007 and accepted for exchange; (ii) approximately $57,000 in cash in lieu of New Notes; and (iii) accrued and unpaid interest to, but not including, the settlement date with respect to the Old Notes accepted for exchange.

The New Notes were issued only to holders of Old Notes that certified certain matters to Xcel Energy, including their status as either "qualified institutional buyers," as that term is defined in Rule 144A under the Securities Act of 1933, or persons other than "U.S. persons," as that term is defined in Rule 902 under the Securities Act of 1933. The New Notes were issued with a registration rights agreement.

In accordance with the Emerging Issues Task Force Issue No. 96-19 (EITF 96-19), Debtor's Accounting for a Modification or Exchange of Debt Instruments, this transaction was accounted for as an exchange. As such, the fees paid to the bondholders have been associated with the replacement debt instruments and, along with the existing unamortized discount, will be amortized as an adjustment of interest expense over the remaining term of the replacement debt instruments. Also, as required by EITF 96-19, the fees paid to third parties were expensed as incurred and $1.7 million was included in interest charges and other financing costs in the consolidated statements of income.

On June 19, 2007, Xcel Energy filed a registration statement with the SEC to exchange the New Notes for the exchange notes, which have terms identical in all material respects to the New Notes, except that the exchange notes do not contain transfer restrictions nor are they subject to registration rights. The exchange offer was completed on Dec. 20, 2007.

## 6. Generating Plant Ownership and Operation

***Joint Plant Ownership*** — Following are the investments by Xcel Energy's subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2007:

| | Plant in Service | Accumulated Depreciation | Construction Work in Progress | Ownership% |
|---|---|---|---|---|
| | | (Thousands of Dollars) | | |
| NSP-Minnesota | | | | |
| Sherco Unit 3 | $503,311 | $313,733 | $ 6,165 | 59.0 |
| Sherco Common Facilities Units 1, 2 and 3 | 109,836 | 61,681 | 62 | 75.0 |
| Transmission facilities, including substations | 4,832 | 2,130 | — | 59.0 |
| Total NSP-Minnesota | $617,979 | $377,544 | $ 6,227 | |
| PSCo | | | | |
| Hayden Unit 1 | $ 87,160 | $ 51,527 | $ 494 | 75.5 |
| Hayden Unit 2 | 80,523 | 50,191 | 1,160 | 37.4 |
| Hayden Common Facilities | 30,019 | 10,634 | 176 | 53.1 |
| Craig Units 1 and 2 | 53,145 | 30,467 | 327 | 9.7 |
| Craig Common Facilities Units 1, 2 and 3 | 32,584 | 13,344 | 643 | 6.5-9.7 |
| Comanche Unit 3 | — | — | 479,499 | 66.7 |
| Transmission and other facilities, including substations | 141,031 | 51,341 | 1,101 | 11.6-68.1 |
| Total PSCo | $424,462 | $207,504 | $483,400 | |

NSP-Minnesota is part owner of Sherco 3, an 860-MW, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for funding its portion of the construction costs.

PSCo's current operational assets include approximately 320 MWs of jointly owned generating capacity. PSCo's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs. PSCo began major construction on a new jointly owned 750 MW, coal-fired unit in Pueblo, Colo. in January 2006. Major construction on the new unit, Comanche 3, is expected to be completed in the fall of 2009. PSCo is the operating agent under the joint ownership agreement.

***Nuclear Plant Operation*** — On Sept. 28, 2007, Xcel Energy obtained 100 percent ownership in NMC as a result of WEC exiting the partnership due to the sale of its Point Beach Nuclear Plant to FPL Energy. Accordingly, the results of operations of NMC and the estimated fair value of assets and liabilities were consolidated in Xcel Energy's consolidated financial statements from the Sept. 28, 2007 transaction date. WEC was required to pay an exit fee and surrender all of its equity interest in NMC upon exiting. The effect of this transaction was not material to the financial position or the results of operations to Xcel Energy. Xcel Energy is in the process of reintegrating its nuclear operations into its generation operations and apply to the NRC to transfer the nuclear operating licenses from NMC to NSP-Minnesota. The transfer of licenses is expected to be completed in early 2008.

## 7. Income Taxes

***COLI*** — As previously disclosed, Xcel Energy and the U.S. government settled an ongoing dispute regarding PSCo's right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by PSRI, a wholly owned subsidiary of PSCo. The total exposure for the tax years in dispute through 2007 was approximately $583 million, which includes income tax, interest and potential penalties. In September 2007, Xcel Energy and the United States finalized a settlement, which terminated the tax litigation pending between the parties. As a result of the settlement, the lawsuit filed by Xcel Energy in the United States District Court has been dismissed and the Tax Court proceedings are in the process of being dismissed.

### Terms of the Final Settlement

1. Xcel Energy paid the government a total of $64.4 million in full settlement of the government's claims for tax, penalty, and interest for tax years 1993-2007. Xcel Energy paid the settlement as follows:
   - $32.2 million was satisfied by tax and interest amounts that Xcel Energy had previously paid or deemed under the terms of the settlement to have been paid.
   - $32.2 million was paid by Xcel Energy on Oct. 31, 2007.

2. The recognition of this settlement resulted in total expense of $59.5 million, including federal and state tax, interest on the federal and state tax liabilities, penalties, and tax benefits on the interest expense for the nine months ended Sept. 30, 2007. The expense of $59.5 million includes $43.4 million of interest and penalties and income tax of $16.1 million (net of tax benefit on the interest expense of $14.3 million).
3. Xcel Energy surrendered the policies to its insurer on Oct. 31, 2007, without recognizing a taxable gain.

***Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109 (FIN 48)*** — Xcel Energy adopted FIN 48 as of Jan. 1, 2007. Xcel Energy files a consolidated federal income tax return, state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns.

Xcel Energy has been audited by the IRS through tax year 2003, with a limited exception for 2003 research tax credits. The IRS commenced an examination of Xcel Energy's federal income tax returns for 2004 and 2005 (and research credits for 2003) in the third quarter of 2006, and that examination is anticipated to be complete by March 31, 2008. As of Dec. 31, 2007, the IRS has not proposed any material adjustments to tax years 2003 through 2005. The statute of limitations applicable to Xcel Energy's 2000 through 2002 federal income tax returns expired as of June 30, 2007.

As previously disclosed, Xcel Energy was in litigation with the federal government to establish its right to deduct interest expense on COLI policy loans incurred since 1993. Xcel Energy and the IRS have reached a final settlement regarding this litigation (see above discussion of COLI).

Xcel Energy is also currently under examination by the state of Minnesota for years 1998 through 2001 and the state of Texas for years 2003 through 2005. No material adjustments have been proposed as of Dec. 31, 2007 for these state audits. In the fourth quarter of 2007, the states of Colorado and Wisconsin concluded income tax audits through tax year 2005. As of Dec. 31, 2007, Xcel Energy's earliest open tax years in which an audit can be initiated by state taxing authorities in its major operating jurisdictions are as follows: Colorado-2002, Minnesota-1998, Texas-2003, and Wisconsin-2002.

The amount of unrecognized tax benefits reported in continuing operations was $42.6 million on Jan. 1, 2007 and $26.3 million on Dec. 31, 2007. The amount of unrecognized tax benefits reported in discontinued operations was $4.7 million on Jan. 1, 2007 and $4.3 million on Dec. 31, 2007. A reconciliation of the beginning and ending amount of unrecognized tax benefit in continuing operations is as follows:

| | (Millions of Dollars) |
|---|---|
| Balance at Jan. 1, 2007 | $ 42.6 |
| Additions based on tax positions related to the current year | 10.4 |
| Reductions based on tax positions related to the current year | (0.4) |
| Additions for tax positions of prior years | 42.3 |
| Reductions for tax positions of prior years | (5.0) |
| Settlements with taxing authorities | (63.6) |
| Balance at Dec. 31, 2007 | $ 26.3 |

These unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss and tax credit carryovers reported in continuing operations of $14.3 million on Jan. 1, 2007 and $7.8 million on Dec. 31, 2007 and net operating loss and tax credit carryovers reported in discontinued operations of $28.9 million on Jan. 1, 2007 and $17.8 million on Dec. 31, 2007.

The unrecognized tax benefit balance reported in continuing operations included $12.7 million and $9.8 million of tax positions on Jan. 1, 2007 and Dec. 31, 2007, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $29.9 million and $16.5 million of tax positions on Jan. 1, 2007 and Dec. 31, 2007, respectively, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The change in the unrecognized tax benefit balance reported in continuing operations of $16.3 million from Jan. 1, 2007 to Dec. 31, 2007, was due to the addition of similar uncertain tax positions related to ongoing activity and the resolution of certain federal and state audit matters. Xcel Energy's amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the IRS and state audits progress. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change. However, as state taxing authorities complete the audits that are currently in progress, it is reasonably possible that the amount of unrecognized tax benefits in continuing operations could decrease up to $5 million.

The liability for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with net operating loss and tax credit carryovers. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in 2007 was $43.7 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $5.8 million on Dec. 31, 2007. The amount of interest expense related to unrecognized tax benefits reported within interest charges in discontinued operations in 2007 was $1.6 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $0.5 million on Dec. 31, 2007.

The amount of penalty expense related to unrecognized tax benefits reported within interest charges in continuing operations in 2007 was $3.2 million. The liability for penalties related to unrecognized tax benefits reported in continuing operations was $1.0 million on Dec. 31, 2007.

***Other Income Tax Matters*** — Xcel Energy's federal net operating loss and tax credit carry forwards are estimated to be $459 million and $140 million, respectively, as of Dec. 31, 2007. A portion of the net operating loss in the amount of $282 million and a portion of the tax credit carry forward in the amount of $51 million are included in discontinued operations. The carry forward periods expire in 2023 and 2024. Xcel Energy also has state net operating loss and tax credit carry forwards of $1.4 billion and $15 million, respectively, as of Dec. 31, 2007. A portion of the state net operating loss in the amount of $1.3 billion and a portion of the tax credit carry forward in the amount of $1 million are included in discontinued operations. The state carry forward periods expire between 2014 and 2024. Xcel Energy has a valuation allowance for its state net operating loss carry forward in the amount of $16 million, primarily reported in discontinued operations. A valuation allowance recorded in prior years against deferred tax assets for capital loss carry forwards related to discontinued operations was reduced to zero from $44 million during 2006 due to capital gains.

Total income tax expense from continuing operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The following is a table reconciling such differences for the years ending Dec. 31:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Federal statutory rate | 35.0% | 35.0% | 35.0% |
| Increases (decreases) in tax from: | | | |
| State income taxes, net of federal income tax benefit | 4.5 | 3.0 | 2.4 |
| Life insurance policies | (3.7) | (4.6) | (4.7) |
| Tax credits recognized, net of federal income tax expense | (2.5) | (3.2) | (4.2) |
| Capital loss carry forward utilization | — | (2.6) | (0.2) |
| Resolution of income tax audits and other | (0.7) | (1.5) | (0.3) |
| Regulatory differences — utility plant items | (1.1) | (0.5) | (0.3) |
| FIN 48 expense — unrecognized tax benefits | 3.1 | — | — |
| Other — net | (0.8) | (1.4) | (1.9) |
| Effective income tax rate from continuing operations | 33.8% | 24.2% | 25.8% |

The components of Xcel Energy's income tax expense (benefit) from continuing operations for the years ending Dec. 31 were:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Current federal tax expense (benefit) | $ 10,649 | $209,941 | $ (4,122) |
| Current state tax expense (benefit) | 6,726 | 41,119 | (15,733) |
| Current FIN 48 tax expense | 20,512 | — | — |
| Current tax credits | — | — | (45) |
| Deferred federal tax expense (benefit) | 225,971 | (35,795) | 191,945 |
| Deferred state tax expense (benefit) | 47,555 | (8,503) | 31,235 |
| Deferred FIN 48 tax expense | 6,926 | — | — |
| Deferred tax credits | (15,175) | (15,545) | (18,122) |
| Deferred investment tax credits | (8,680) | (9,806) | (11,619) |
| Total income tax expense from continuing operations | $294,484 | $181,411 | $173,539 |

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

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| Deferred tax liabilities: | | |
| Differences between book and tax bases of property | $2,535,181 | $2,306,160 |
| Regulatory assets | 182,215 | 153,749 |
| Employee benefits | 16,707 | 25,291 |
| Service contracts | 6,724 | 7,592 |
| Partnership income/loss | 5,119 | 4,248 |
| Other | 31,965 | 29,826 |
| Total deferred tax liabilities | $2,777,911 | $2,526,866 |
| Deferred tax assets: | | |
| Net operating loss carry forward | $ 77,350 | $ 101,316 |
| Tax credit carry forward | 103,585 | 99,025 |
| Other comprehensive income | 19,794 | 14,808 |
| Deferred investment tax credits | 44,220 | 47,606 |
| Regulatory liabilities | 32,608 | 41,254 |
| Accrued liabilities and other | 70,079 | 71,572 |
| Total deferred tax assets | $ 347,636 | $ 375,581 |
| Net deferred tax liability | $2,430,275 | $2,151,285 |

## 8. Preferred and Common Stock

***Preferred Stock*** — Xcel Energy has authorized 7,000,000 shares of preferred stock with a $100 par value. At Dec. 31, 2007 and 2006, Xcel Energy had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends. The holders of the $3.60 series preferred stock are entitled to three votes per each share held. The holders of the other series of preferred stock are entitled to one vote per share. In the event 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. The holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of Xcel Energy's subsidiaries also authorize the issuance of preferred stock. However, at Dec. 31, 2007 and 2006, there are no preferred shares of subsidiaries outstanding.

| | Preferred Shares Authorized | Par Value | Preferred Shares Outstanding |
|---|---|---|---|
| SPS | 10,000,000 | $1.00 | None |
| PSCo | 10,000,000 | 0.01 | None |

***Common Stock and Equivalents*** — Xcel Energy has common stock equivalents consisting of convertible senior notes, 401(k) equity awards, restricted stock units and stock options, as discussed later. Restricted stock units and performance shares are included as common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the period being reported.

In 2007, 2006 and 2005, Xcel Energy had approximately 8.5 million, 11.0 million and 13.3 million options outstanding, respectively, that were antidilutive and, therefore, excluded from the earnings per share calculation. The dilutive impact of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

| | 2007 | | | 2006 | | | 2005 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Income | Shares | Per Share Amount | Income | Shares | Per Share Amount | Income | Shares | Per Share Amount |
| | (Shares and dollars in thousands, except per share amounts) | | | | | | | | |
| Income from continuing operations | $575,899 | | | $568,681 | | | $499,038 | | |
| Less: Dividend requirements on preferred stock | (4,241) | | | (4,241) | | | (4,241) | | |
| **Basic earnings per share** | | | | | | | | | |
| Income from continuing operations | 571,658 | 416,139 | $1.38 | 564,440 | 405,689 | $1.39 | 494,797 | 402,330 | $1.23 |
| Effect of dilutive securities: | | | | | | | | | |
| Convertible debt | 10,411 | 16,425 | | 15,112 | 23,317 | | 14,373 | 23,317 | |
| 401(k) equity awards | — | 482 | | — | 551 | | — | — | |
| Options | — | 85 | | — | 48 | | — | 24 | |
| **Diluted earnings per share** | | | | | | | | | |
| Income from continuing operations and assumed conversions | $582,069 | 433,131 | $1.35 | $579,552 | 429,605 | $1.35 | $509,170 | 425,671 | $1.20 |

***Common Stock Dividends Per Share*** — Historically, Xcel Energy has paid quarterly dividends to its shareholders. Dividends on common stock are paid as declared by the board of directors. Dividends declared per share for the quarters of 2007, 2006 and 2005 are:

| Dividends Per Share | 2007 | 2006 | 2005 |
|---|---|---|---|
| First Quarter | $0.2225 | $0.2150 | $0.2075 |
| Second Quarter | 0.2300 | 0.2225 | 0.2150 |
| Third Quarter | 0.2300 | 0.2225 | 0.2150 |
| Fourth Quarter | 0.2300 | 0.2225 | 0.2150 |
| | **$0.9125** | **$0.8825** | **$0.8525** |

***Dividend and Other Capital-Related 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. Under the provisions, dividend payments may be restricted if Xcel Energy's capitalization ratio (on a holding company basis only and not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, the capitalization ratio at Dec. 31, 2007 and 2006, was 85 percent and 81 percent, respectively. Therefore, the restrictions do not place any effective limit on Xcel Energy's ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of Xcel Energy common stock.

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 $946 million and $905 million in additional cash dividends on common stock at Dec. 31, 2007 and 2006, respectively.

The issuance of securities by Xcel Energy generally is not subject to regulatory approval. However, utility financings and certain intra-system financings are subject to the jurisdiction of the applicable state regulatory commissions and/or the FERC under the Federal Power Act.

- PSCo currently has authorization to issue up to $850 million of long-term debt and up to $800 million of short-term debt at any one time outstanding.
- SPS currently has authorization to issue up to $400 million in short-term debt.
- NSP-Wisconsin currently has authorization to issue up to $125 million of long-term debt and $75 million of short-term debt.
- NSP-Minnesota has authorization to issue long-term securities provided the equity ratio remain between 45.99 percent and 56.21 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $6.7 billion.

Xcel Energy believes these authorizations are adequate and will seek additional authorization when necessary, however, there can be no assurance that additional authorization will be granted on the timeframe or in the amounts requested.

The FERC has granted a blanket authorization for certain intra-system financings involving holding companies. In addition, Xcel Energy's utility subsidiaries have received FERC authorization through June 30, 2008 to engage in intra-system financings, including through the money pool, in amounts ranging from $250 million for each of NSP-Minnesota and PSCo, to $100 million for SPS and $75 million for NSP-Wisconsin.

***Stockholder Protection Rights Agreement*** — In June 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.

## 9. Share-Based Compensation

Effective Jan. 1, 2006, Xcel Energy adopted the provisions of SFAS No. 123(R), which requires the measurement and recognition of compensation expense in an amount equal to the fair value of share-based payment awards granted to employees and directors including stock option awards, restricted stock, restricted stock units and performance share awards. Xcel Energy previously applied the provisions of Accounting Principles Board Opinion No. 25 — "Accounting for Stock Issued to Employees" and related Interpretations in order to provide the required pro forma disclosures under SFAS No. 123, "Accounting for Share-based Compensation," ("SFAS No. 123"). Xcel Energy adopted SFAS No. 123(R) using the modified prospective transition method. Accordingly, in 2006, Xcel Energy recorded share based compensation expense for awards granted prior to but not yet vested as of Jan, 1, 2006 as if the fair value method required for pro forma disclosure under SFAS No. 123 were in effect for expense recognition purposes.

The pro forma information for share based compensation in 2005 was as follows:

| | 2005 (Thousands of Dollars, except per share amounts) |
|---|---|
| Net income — as reported | $512,972 |
| Less: Total share-based employee compensation expense determined under fair-value-based method for stock options, net of related tax effects | (1,180) |
| Pro forma net income | $511,792 |
| Earnings per share: | |
| Basic — as reported | $ 1.26 |
| Basic — pro forma | 1.26 |
| Diluted — as reported | 1.23 |
| Diluted — pro forma | 1.23 |

***Stock Options*** — Xcel Energy has incentive compensation plans under which stock options and other performance incentives are awarded to key employees. In the past, Xcel Energy issued stock options, but has not granted stock options since December 2001. The weighted average number of common and potentially dilutive shares outstanding used to calculate Xcel Energy's earnings per share include 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.

Activity in stock options was as follows for the years ended Dec. 31:

| | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| (Awards in thousands) | Awards | Average Price | Awards | Average Price | Awards | Average Price |
| Outstanding beginning of year | 12,374 | $27.36 | 13,576 | $26.92 | 14,606 | $26.67 |
| Exercised | (266) | 19.18 | (563) | 18.33 | (152) | 17.30 |
| Forfeited | (50) | 27.43 | (89) | 26.98 | (213) | 26.84 |
| Expired | (2,511) | 29.37 | (550) | 25.66 | (665) | 23.71 |
| Outstanding at end of year | 9,547 | 27.19 | 12,374 | 27.36 | 13,576 | 26.92 |
| Exercisable at end of year | 9,547 | 27.19 | 12,374 | 27.36 | 13,529 | 26.91 |

| | Range of Exercise Prices | | |
|---|---|---|---|
| | $15.94 to $26.00 | $26.01 to $30.00 | $30.01 to $51.25 |
| Options outstanding and exercisable: | | | |
| Number outstanding and exercisable | 3,060,850 | 5,504,321 | 982,156 |
| Weighted average remaining contractual life (years) | 3.2 | 2.5 | 2.3 |
| Weighted average exercise price | $ 23.72 | $ 26.95 | $ 39.32 |

The total fair value of stock options exercised and the total intrinsic value of options exercised during the years ended Dec. 31, 2007, 2006, 2005 are as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Fair value of stock options exercised | $6,398 | $12,108 | $2,906 |
| Intrinsic value of options exercised[(a)] | 1,293 | 1,795 | 281 |

(a) Intrinsic value is calculated as market price at exercise date less the option exercise price

***Restricted Stock*** — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Executive Annual Incentive Award Plan. Restricted stock vests in equal annual installments over a three-year period. Xcel Energy reinvests dividends on the restricted stock it holds while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a value equal to the market-trading price of Xcel Energy's stock at the grant date. Xcel Energy granted the shares of restricted stock in 2007, 2006 and 2005 as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Granted shares | 37,000 | 10,481 | 28,626 |
| Grant-date market price | $ 24.27 | $ 19.10 | $ 17.81 |

A summary of the status of our nonvested restricted stock as of Dec. 31, 2007, and changes during the year ended Dec. 31, 2007 are as follows:

| | Shares | Weighted Average Grant Date Fair Value Price |
|---|---|---|
| | (Shares in thousands) | |
| Nonvested restricted stock at Jan. 1, 2007 | 29,476 | $18.17 |
| Granted | 37,000 | 24.27 |
| Vested | (17,147) | 17.89 |
| Forfeited | (2,941) | 18.45 |
| Earned dividends | 1,766 | 22.31 |
| Nonvested restricted stock at Dec. 31, 2007 | 48,154 | 23.13 |

***Restricted Stock Units*** — Xcel Energy's board of directors has granted restricted stock units under the Xcel Energy Omnibus Incentive Plan approved by the shareholders in 2000 and under the Xcel Energy 2005 Omnibus Incentive Plan. Both plans allow the utilization of various performance goals on the restricted stock units granted. The performance goals may vary by plan year. Under no circumstances will the restrictions on restricted stock units lapse, even if performance goals have been achieved, until one year after the grant date for restricted stock units granted in 2004. The restrictions on restricted stock units granted in 2005, 2006 and 2007 will not lapse, under any circumstances, even if performance goals have been achieved, until two years after the grant date.

On Jan. 2, 2004, Xcel Energy granted 512,638 restricted stock units under the Xcel Energy Omnibus Incentive Plan. The grant-date market price used to calculate the total shareholder return (TSR) for this grant is $17.03. On Aug. 2, 2006, the restrictions lapsed on the restricted stock units, and Xcel Energy issued approximately 0.4 million shares of common stock after approximately 0.2 million shares were withheld for tax purposes.

For years ended Dec. 31, 2007, 2006 and 2005, the restricted stock units awarded were as follows:

| (Units in thousands) | 2007 | 2006 | 2005 |
|---|---|---|---|
| Units granted | 313 | 390 | 519 |
| Fair value at grant date | $19.08 | $15.13 | $18.10 |

Payout of the units and the lapsing of restrictions on the transfer of units are based on two separate performance criteria. A portion of the awarded units, plus associated earned dividend equivalents will be settled and the restricted period will lapse after Xcel Energy achieves a specified earnings per share growth (adjusted for COLI). Additionally, Xcel Energy's annual dividend paid on its common stock must remain at $0.83 per share or greater. Earnings per share growth will be measured annually at the end of each fiscal year. The remaining awarded units plus associated earned dividend equivalents will be settled, and the restricted period will lapse after the average of actual performance results for the three components of an environmental index measured as a percentage of target performance meets or exceeds 100 percent. The environmental index will be measured annually at the end of each fiscal year. If the performance criteria have not been met within four years of the date of grant, all associated units shall be forfeited. The 2005 environmental restricted stock units met their target as of Dec. 31, 2006 and were settled in shares in February 2007. The 2005 restricted stock units measured on EPS growth and all 2006 restricted stock units met their targets and will be settled in shares in the first quarter of 2008.

A summary of the status of our nonvested restricted stock units as of Dec. 31, 2007, and changes during the year ended Dec. 31, 2007 are as follows:

| | Share/Units | Weighted Average Grant Date Fair Value Price |
|---|---|---|
| | (Share/Units in thousands) | |
| Nonvested restricted stock units at Jan. 1, 2007 | 861 | $16.76 |
| Granted | 313 | 19.08 |
| Vested | (845) | 16.80 |
| Forfeited | (73) | 17.06 |
| Earned dividend equivalents | 43 | 17.26 |
| Nonvested restricted stock units at Dec. 31, 2007 | 299 | 19.08 |

The total aggregate intrinsic value of nonvested restricted stock units as of Dec. 31, 2007 was $1.0 million and the weighted average remaining contractual life was 2.2 years.

The total fair value and total intrinsic value of restricted stock units vested during the years ended Dec. 31, 2007, 2006 and 2005 were as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| Fair value of restricted stock units vested | $14,192 | $10,561 | $— |
| Intrinsic value of restricted stock units vested[a] | 4,876 | 3,844 | — |

[a] Intrinsic value is calculated as the market price at vesting date less the fair value at grant date

*Performance Share Plan Awards (PSP)* — Xcel Energy's board of directors has granted performance share awards under the Xcel Energy Omnibus Incentive Plan approved by the shareholders in 2000 and under the Xcel Energy 2005 Omnibus Incentive Plan. Both plans allow Xcel Energy to utilize various performance goals on the performance share awards granted. The PSP has been entirely dependent on a single measure, the TSR and it is measured over a three-year period. Xcel Energy's TSR is compared to the TSR of other companies in the Edison Electric Institute's Electrics Index. At the end of the three-year period, potential payouts of the performance share awards range from 0 percent to 200 percent, depending on the Xcel Energy's TSR compared to the peer group.

On Jan. 2, 2004, Xcel Energy granted 323,548 performance share awards under the Xcel Energy Omnibus Incentive Plan. The grant-date market price used to calculate the TSR for this grant was $17.03. The 2004 performance share awards met the TSR requirements as of Dec. 31, 2006 and were settled in shares and cash in February 2007.

For years ended Dec. 31, 2007, 2006 and 2005, the PSP awards granted were as follows:

| (Awards in thousands) | 2007 | 2006 | 2005 |
|---|---|---|---|
| Share awards granted | 231 | 262 | 324 |
| Fair value at grant date | $17.33 | $13.64 | $18.10 |
| Vesting period (in years) | 3 | 3 | 3 |

The 2005 performance share awards were granted under the Xcel Energy Omnibus Incentive Plan whereas the 2006 and 2007 awards were granted under the Xcel Energy 2005 Omnibus Incentive Plan. The 2005 performance share awards met the TSR requirements as of Dec. 31, 2007 and will be settled in shares and cash in the first quarter of 2008.

The total fair value and total intrinsic value of performance awards settled during the years ended Dec. 31, 2007, 2006 and 2005 were as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (in thousands) | |
| Share awards settled | 395 | 1,139 | — |
| Fair value of share awards settled | $6,723 | $12,647 | — |
| Intrinsic value of share awards settled[a] | 2,890 | 9,109 | — |

[a] Intrinsic value is calculated as the market price at settlement less than the fair value at grant date

***Share-Based Compensation Plan Expense*** — The vesting of the restricted stock units is predicated on the achievement of a performance condition which is the achievement of an earnings per share or environmental measures target. The fair values used to calculate the expense on these plans are based on the amount of the award calculated as a percentage of salaries and approved by Xcel Energy's board of directors. Restricted stock unit awards are considered to be equity awards. Since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement.

The performance share plan awards have been historically settled partially in cash and therefore do not qualify as an equity award, but are accounted for as a liability award. As a liability award, the fair value on which expense is based is remeasured each period based on the current stock price and final expense is based on the market value of the shares on the date the award is settled.

The compensation costs related to share-based awards for the years ended Dec. 31, 2007, 2006 and 2005 were as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Compensation cost for share-based awards[a][b] | $24,900 | $43,253 | $29,350 |
| Tax benefit recognized in income | 9,661 | 16,777 | 11,306 |
| Total compensation cost capitalized | 3,697 | 3,680 | 3,557 |

[a] Compensation costs for share-based payment arrangements is included in Other Operating and Maintenance Expense on our consolidated statements of income

[b] Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totalled $15.2 million, $15.0 million and $14.3 million for the years ended 2007, 2006 and 2005, respectively.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Omnibus Incentive Plan, approved in 2000, is 14.5 million and 8.3 million was approved under the Xcel Energy 2005 Omnibus Incentive Plan. Under the Executive Annual Incentive Plan approved in 2000, the total number of share approved for issuance is 1.5 million and 1.2 million shares were approved under the Executive Annual Incentive Plan in 2005.

As of Dec. 31, 2007, there was approximately $6.5 million of total unrecognized compensation cost related to non-vested share-based compensation awards. Total unrecognized compensation expense will be adjusted for future changes in estimated forfeitures. Xcel Energy expects to recognize that cost over a weighted-average period of 1.8 years. The amount of cash used to settle these awards was $7.8 million in 2007 and $11.9 million in 2006.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended Dec. 31 were as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Cash received from stock options exercised | $5,266 | $10,231 | $2,642 |
| Tax benefit realized for the tax deductions from stock options exercised | — | 353 | 6 |

## 10. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees. Approximately 52 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2007:

- NSP-Minnesota had 2,287 and NSP-Wisconsin had 408 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2010.
- PSCo had 2,194 bargaining employees covered under a collective-bargaining agreement, which expires in May 2009.
- SPS had 774 bargaining employees covered under a collective-bargaining agreement, which expires in October 2008.

**"Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)" (SFAS No. 158)** — In September 2006, the FASB issued SFAS No. 158, which requires companies to fully recognize the funded status of each pension and other postretirement benefit plan as a liability or asset on their balance sheets with all unrecognized amounts to be recorded in other comprehensive income. Xcel Energy applied regulatory accounting treatment for unrecognized amounts of regulated utility subsidiary employees, which allowed recognition as a regulatory asset or liability rather than as a charge to accumulated other comprehensive income, as future costs are expected to be included in rates. The effect of adopting in 2006 for the remaining unrecognized amounts was an increase in accumulated other comprehensive income of $72.8 million.

## Pension Benefits

Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all 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.

***Pension Plan Assets*** — Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. The target range for our pension asset allocation is 60 percent in equity investments, 20 percent in fixed income investments and 20 percent in nontraditional investments, such as real estate, private equity and a diversified commodities index.

The actual composition of pension plan assets at Dec. 31 was:

| | 2007 | 2006 |
|---|---|---|
| Equity securities | 60% | 63% |
| Debt securities | 22 | 22 |
| Real estate | 4 | 4 |
| Cash | 2 | 2 |
| Nontraditional investments | 12 | 9 |
| | 100% | 100% |

Xcel Energy bases its investment-return assumption on expected long-term performance for each of the investment types included in its pension asset portfolio. Xcel Energy considers the actual historical returns achieved by its asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts. The historical weighted average annual return for the past 20 years for the Xcel Energy portfolio of pension investments is 11.8 percent, which is greater than the current assumption level. The pension cost determination assumes the continued current mix of investment types over the long term. The Xcel Energy portfolio is heavily weighted toward equity securities and includes nontraditional investments. A higher weighting in equity investments can increase the volatility in the return levels achieved by pension assets in any year. Investment returns in 2007 were below the assumed level of 8.75 percent while returns in 2006 and 2005 exceeded the assumed level of 8.75 percent. Xcel Energy continually reviews its pension assumptions. In 2008, Xcel Energy will continue to use an investment-return assumption of 8.75 percent.

***Benefit Obligations*** — A comparison of the actuarially computed pension-benefit obligation and plan assets, on a combined basis, is presented in the following table:

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| **Accumulated Benefit Obligation at Dec. 31** | $2,497,898 | $2,486,370 |
| **Change in Projected Benefit Obligation** | | |
| Obligation at Jan. 1 | $2,666,555 | $2,796,780 |
| Service cost | 61,392 | 61,627 |
| Interest cost | 162,774 | 155,413 |
| Plan amendments | (19,955) | (16,569) |
| Actuarial (gain) loss | 23,325 | (82,339) |
| Benefit payments | (231,332) | (248,357) |
| Obligation at Dec. 31 | $2,662,759 | $2,666,555 |
| **Change in Fair Value of Plan Assets** | | |
| Fair value of plan assets at Jan. 1 | $3,183,375 | $3,093,536 |
| Actual return on plan assets | 199,230 | 306,196 |
| Employer contributions | 35,000 | 32,000 |
| Benefit payments | (231,332) | (248,357) |
| Fair value of plan assets at Dec. 31 | $3,186,273 | $3,183,375 |
| **Funded Status of Plans at Dec. 31** | | |
| Funded status | $ 523,514 | $ 516,820 |
| Noncurrent assets | 568,055 | 586,712 |
| Noncurrent liabilities | (44,541) | (69,892) |
| Net pension amounts recognized on consolidated balance sheets | $ 523,514 | $ 516,820 |
| **Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:** | | |
| Net loss | $ 216,776 | $ 143,695 |
| Prior service cost | 123,426 | 168,437 |
| Total | $ 340,202 | $ 312,132 |
| **SFAS No. 158 Amounts Have Been Recorded as Follows Based Upon Expected Recovery in Rates:** | | |
| Regulatory assets | $ 205,720 | 208,216 |
| Regulatory liabilities | 111,650 | 89,627 |
| Deferred income taxes | 9,780 | 6,312 |
| Net-of-tax AOCI | 13,052 | 7,977 |
| Total | $ 340,202 | 312,132 |
| Measurement Date | Dec. 31, 2007 | Dec. 31, 2006 |
| **Significant Assumptions Used to Measure Benefit Obligations** | | |
| Discount rate for year-end valuation | 6.25% | 6.00% |
| Expected average long-term increase in compensation level | 4.00 | 4.00 |

At Dec. 31, 2007, one of Xcel Energy's pension plans had projected benefit obligations of $732.7 million, which exceeded plan assets of $688.1 million. At Dec. 31, 2006, the projected benefit obligations of $728.1 million, exceeded plan assets of $658.2 million. All other Xcel Energy plans in the aggregate had plan assets of $2.5 billion and projected benefit obligations of $1.9 billion on Dec. 31, 2007.

***Cash Flows*** — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2005 through 2007 for Xcel Energy's pension plans and are not expected to require cash funding in 2008.

- Voluntary contributions were made to the PSCo Bargaining Pension Plan of $35 million in 2007, $30 million in 2006 and $15 million in 2005.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of $2 million in 2006 and $5 million in 2005. No voluntary contributions were made to the plan during 2007.
- During 2008, Xcel Energy expects to voluntarily contribute approximately $35 million to the PSCo pension plan for bargaining employees and does not expect to contribute to the NCE non-bargaining plan.

***Plan Changes*** — The Pension Protection Act of 2006 (PPA) was effective Dec. 31, 2006. PPA requires a change in the conversion basis for lump-sum payments and three-year vesting for plans with account balance or pension equity benefits. These changes are reflected as a plan amendment for purposes of SFAS No. 87-"Employers' Accounting for Pensions".

***Benefit Costs*** — The components of net periodic pension cost (credit) are:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Service cost | $ 61,392 | $ 61,627 | $ 60,461 |
| Interest cost | 162,774 | 155,413 | 160,985 |
| Expected return on plan assets | (264,831) | (268,065) | (280,064) |
| Amortization of prior service cost | 25,056 | 29,696 | 30,035 |
| Amortization of net loss | 15,845 | 17,353 | 6,819 |
| Net periodic pension cost (credit) under SFAS No. 87 | 236 | (3,976) | (21,764) |
| Credits not recognized due to effects of regulation | 9,682 | 12,637 | 19,368 |
| Net benefit credit recognized for financial reporting | $ 9,918 | $ 8,661 | $ (2,396) |
| **Significant Assumptions Used to Measure Costs** | | | |
| Discount rate | 6.00% | 5.75% | 6.00% |
| Expected average long-term increase in compensation level | 4.00 | 3.50 | 3.50 |
| Expected average long-term rate of return on assets | 8.75 | 8.75 | 8.75 |

Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The return assumption used for 2008 pension cost calculations will be 8.75 percent. The cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value begins with the fair market value of assets as of the beginning of the year. The market-related value is determined by adjusting the fair market value of assets to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year.

Xcel Energy also 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) plans that cover substantially all employees. Total contributions to these plans were approximately $21.8 million in 2007, $18.3 million in 2006 and $19.6 million in 2005.

## Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to most Xcel Energy retirees.

- The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for former NCE nonbargaining employees retiring after June 30, 2003.
- Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NSP who retired after 1998, bargaining employees of the former NSP who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

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 (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy's retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. 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.

***Plan Assets*** — Certain state agencies that regulate Xcel Energy's utility subsidiaries also 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 is required to fund SFAS No. 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

The actual composition of postretirement benefit plan assets at Dec. 31 was:

| | 2007 | 2006 |
|---|---|---|
| Equity and equity mutual fund securities | 67% | 67% |
| Fixed income/debt securities | 21 | 21 |
| Cash equivalents | 11 | 11 |
| Nontraditional investments | 1 | 1 |
| | 100% | 100% |

Xcel Energy bases its investment-return assumption for the postretirement health care fund assets on expected long-term performance for each of the investment types included in its postretirement health care asset portfolio. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

***Benefit Obligations*** — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table:

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| **Change in Benefit Obligation** | | |
| Obligation at Jan. 1 | $ 918,693 | $ 938,172 |
| Service cost | 5,813 | 6,633 |
| Interest cost | 50,475 | 52,939 |
| Medicare subsidy reimbursements | 2,526 | 3,561 |
| Plan amendments | — | (945) |
| Plan participants' contributions | 13,211 | 11,870 |
| Actuarial gain | (86,576) | (27,511) |
| Benefit payments | (73,827) | (66,026) |
| Obligation at Dec. 31 | $ 830,315 | $ 918,693 |
| **Change in Fair Value of Plan Assets** | | |
| Fair value of plan assets at Jan. 1 | $ 406,305 | $ 351,863 |
| Actual return on plan assets | 24,623 | 41,409 |
| Plan participants' contributions | 13,211 | 11,870 |
| Employer contributions | 57,147 | 67,188 |
| Benefit payments | (73,827) | (66,025) |
| Fair value of plan assets at Dec. 31 | $ 427,459 | $ 406,305 |
| **Funded Status at Dec. 31** | | |
| Funded status | $(402,856) | $(512,388) |
| Current liabilities | (1,755) | (2,211) |
| Noncurrent liabilities | (401,101) | (510,177) |
| Net amounts recognized on consolidated balance sheets | $(402,856) | $(512,388) |
| **Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:** | | |
| Net loss | $ 202,748 | $ 297,745 |
| Prior service credit | (11,380) | (13,558) |
| Transition obligation | 73,056 | 87,633 |
| Total | $ 264,424 | $ 371,820 |
| **SFAS No. 158 Amounts Have Been Recorded as Follows Based upon Expected Recovery in Rates:** | | |
| Regulatory assets | $ 154,661 | $ 235,834 |
| Regulatory liabilities | 97,835 | 118,722 |
| Deferred income taxes | 5,184 | 7,004 |
| Net-of-tax AOCI | 6,744 | 10,260 |
| Total | $ 264,424 | $ 371,820 |
| Measurement Date | Dec. 31, 2007 | Dec. 31, 2006 |
| **Significant Assumptions Used to Measure Benefit Obligations** | | |
| Discount rate for year-end valuation | 6.25% | 6.00% |

Effective Dec. 31, 2007, Xcel Energy reduced its initial medical trend assumption from 9.0 percent to 8.0 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is six years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects:

| | (Thousands of Dollars) |
|---|---|
| 1-percent increase in APBO components at Dec. 31, 2007 | $ 89,985 |
| 1-percent decrease in APBO components at Dec. 31, 2007 | (75,284) |
| 1-percent increase in service and interest components of the net periodic cost | 7,402 |
| 1-percent decrease in service and interest components of the net periodic cost | (6,064) |

*Cash Flows* — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy expects to contribute approximately $49 million during 2008.

*Benefit Costs* — The components of net periodic postretirement benefit costs are:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| Service cost | $ 5,813 | $ 6,633 | $ 6,684 |
| Interest cost | 50,475 | 52,939 | 55,060 |
| Expected return on plan assets | (30,401) | (26,757) | (25,700) |
| Amortization of transition obligation | 14,577 | 14,444 | 14,578 |
| Amortization of prior service credit | (2,178) | (2,178) | (2,178) |
| Amortization of net loss gain | 14,198 | 24,797 | 26,246 |
| Net periodic postretirement benefit cost under SFAS No. 106 | 52,484 | 69,878 | 74,690 |
| Additional cost recognized due to effects of regulation | 3,891 | 3,891 | 3,891 |
| Net cost recognized for financial reporting | $ 56,375 | $ 73,769 | $ 78,581 |
| **Significant assumptions used to measure costs (income)** | | | |
| Discount rate | 6.00% | 5.75% | 6.00% |
| Expected average long-term rate of return on assets (pretax) | 7.50 | 7.50 | 5.50-8.50 |

## Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

| | Projected Pension Benefit Payments | Gross Projected Postretirement Health Care Benefit Payments | Expected Medicare Part D Subsidies | Net Projected Postretirement Health Care Benefit Payments |
|---|---|---|---|---|
| | (Thousands of Dollars) | | | |
| 2008 | $ 215,127 | $ 60,706 | $ 5,841 | $ 54,865 |
| 2009 | 215,407 | 62,674 | 6,280 | 56,394 |
| 2010 | 222,771 | 64,508 | 6,693 | 57,815 |
| 2011 | 222,743 | 66,428 | 7,031 | 59,397 |
| 2012 | 227,616 | 67,497 | 7,415 | 60,082 |
| 2013-2017 | 1,196,905 | 348,035 | 40,849 | 307,186 |

## 11. Detail of Interest and Other Income (Expense), Net

Interest and other income, net of nonoperating expenses, for the years ended Dec. 31 consisted of the following:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| Interest income | $ 24,093 | $ 20,317 | $ 14,886 |
| Equity income in unconsolidated affiliates | 3,459 | 4,450 | 2,511 |
| Other nonoperating income | 4,352 | 5,253 | 8,251 |
| Minority interest income | 599 | 2,361 | 827 |
| Interest expense on corporate-owned life insurance and other insurance policies | (21,548) | (27,637) | (25,000) |
| Other nonoperating expense | (7) | (659) | (618) |
| Total interest and other income, net | $ 10,948 | $ 4,085 | $ 857 |

## 12. Derivative Instruments

In the normal course of business, Xcel Energy and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. Xcel Energy and its subsidiaries utilize, in accordance with approved risk management policies, a variety of derivative instruments to mitigate market risk and to enhance its operations.

***Commodity Price Risk*** — Xcel Energy's utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and other energy-related products and for various fuels used for generation of electricity and in the natural gas utility operations. Commodity risk is also managed through the use of financial derivative instruments. Xcel Energy's utility subsidiaries utilize these derivative instruments to reduce the volatility in the cost of commodities acquired on behalf of its retail customers even though regulatory jurisdiction may provide for recovery of actual costs. The use of derivative instruments is done consistently with the state regulatory cost-recovery mechanism. Xcel Energy's risk-management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

***Short-Term Wholesale and Commodity Trading Risk*** — Xcel Energy's utility subsidiaries conduct various short-term wholesale and commodity trading activities, including the purchase and sale of electric capacity and energy and other energy-related instruments. Xcel Energy's risk-management policy allows management to conduct these activities within guidelines and limitations as approved by our risk-management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

***Interest Rate Risk*** — Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk-management policy allows interest rate risk to be managed through the use of fixed-rate debt, floating-rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

## Types of and Accounting for Derivative Instruments

Xcel Energy and its subsidiaries use derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The types of qualifying hedging transactions that Xcel Energy and its subsidiaries are currently engaged in are discussed below.

## Cash Flow Hedges

***Commodity Cash Flow Hedges*** — Xcel Energy's utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At Dec. 31, 2007, Xcel Energy had various commodity-related contracts classified as cash flow hedges extending through December 2009.

At Dec. 31, 2007, Xcel Energy had $0.5 million in accumulated other comprehensive income related to commodity cash flow hedge contracts that is expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Xcel Energy had immaterial ineffectiveness related to commodity cash flow hedges during 2007 and 2006.

***Interest Rate Cash Flow Hedges*** — Xcel Energy and its subsidiaries enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

At Dec. 31, 2007, Xcel Energy had net losses related to interest rate swaps/locks of approximately $0.4 million in accumulated other comprehensive income that is expected to be recognized in earnings during the next 12 months.

Xcel Energy had immaterial ineffectiveness related to interest rate cash flow hedges during 2007 and no ineffectiveness related to interest rate cash flow hedges during 2006.

The following table shows the major components of the derivative instruments valuation in the consolidated balance sheets at Dec. 31:

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | Derivative Instruments Valuation — Assets | Derivative Instruments Valuation — Liabilities | Derivative Instruments Valuation — Assets | Derivative Instruments Valuation — Liabilities |
| | (Thousands of Dollars) | | | |
| Long-term purchased power agreements | $426,774 | $401,313 | $478,853 | $502,789 |
| Electric and natural gas trading and hedging instruments | 51,106 | 21,694 | 57,797 | 40,881 |
| Interest rate hedging instruments | 535 | 20,223 | 2,432 | 23,351 |
| Total | $478,415 | $443,230 | $539,082 | $567,021 |

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During the first quarter of 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

***Financial Impact of Qualifying Cash Flow Hedges*** — The impact of qualifying cash flow hedges on Xcel Energy's accumulated other comprehensive income, included in the consolidated statements of common stockholders' equity and comprehensive income, is detailed in the following table:

| | (Millions of Dollars) |
|---|---|
| Accumulated other comprehensive income related to hedges at Dec. 31, 2004 | $ 0.1 |
| After-tax net unrealized gains related to derivatives accounted for as hedges | 4.5 |
| After-tax net realized gains on derivative transactions reclassified into earnings | (13.4) |
| Accumulated other comprehensive loss related to hedges at Dec. 31, 2005 | $ (8.8) |
| After-tax net unrealized gains related to derivatives accounted for as hedges | 11.8 |
| After-tax net realized gains on derivative transactions reclassified into earnings | (0.8) |
| Accumulated other comprehensive income related to hedges at Dec. 31, 2006 | $ 2.2 |
| After-tax net unrealized losses related to derivatives accounted for as hedges | (2.6) |
| After-tax net realized gains on derivative transactions reclassified into earnings | (1.0) |
| Accumulated other comprehensive loss related to hedges at Dec. 31, 2007 | $ (1.4) |

## Fair Value Hedges

***Interest Rate Fair Value Hedges*** — Xcel Energy enters into interest rate swap instruments that effectively hedge the fair value of fixed-rate debt. The fair market value of Xcel Energy's interest rate swaps at Dec. 31, 2007, was a liability of approximately $2.6 million.

## 13. Financial Instruments

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

| | 2007 | | 2006 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (Thousands of Dollars) | | | |
| Nuclear decommissioning fund | $1,317,564 | $1,317,564 | $1,200,688 | $1,200,688 |
| Other investments | 40,019 | 40,019 | 29,209 | 28,962 |
| Long-term debt, including current portion | 6,979,695 | 7,269,035 | 6,786,049 | 7,324,218 |

The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. The fair values of Xcel Energy's debt securities in an external nuclear decommissioning fund and other investments are estimated based on quoted market prices for those or similar investments. The fair values of Xcel Energy's long-term debt is 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, 2007 and 2006. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since that date, and current estimates of fair values may differ significantly.

The following tables provide the external decommissioning fund's approximate gains, losses and proceeds from the sale of securities for the years ended Dec. 31:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | (Thousands of Dollars) | | |
| Realized gains | $ 38,745 | $310,066 | $ 8,967 |
| Realized losses | 35,794 | 32,412 | 8,990 |
| Proceeds from sale of securities | 669,070 | 958,294 | 489,697 |

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| Unrealized gains | $80,960 | $41,355 |
| Unrealized losses | — | — |

Xcel Energy provides guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantee. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral.

On Dec. 31, 2007, Xcel Energy had the following amount of guarantees and exposure under these guarantees, including those related to Seren, UE, Quixx and Xcel Energy Argentina, which are components of discontinued operations:

| Nature of Guarantee | Guarantor | Guarantee Amount | Current Exposure | Term or Expiration Date | Triggering Event Requiring Performance | Assets Held as Collateral |
|---|---|---|---|---|---|---|
| | | | (Millions of Dollars) | | | |
| Guarantee performance and payment of surety bonds for itself and its subsidiaries[f] | Xcel Energy | $31.6 | [a] | 2008-2010, 2012, 2014, 2015 and 2022 | [d] | N/A |
| Guarantee the indemnification obligations of Xcel Energy Wholesale Group Inc. under a stock purchase agreement | Xcel Energy | 17.5 | [g] | 2010 | [c] | N/A |
| Guarantee the indemnification obligations of Xcel Energy Argentina under a stock purchase agreement | Xcel Energy | 14.7 | $— | Continuing | [c] | N/A |
| Guarantee the indemnification obligations of Seren under an asset purchase agreement | Xcel Energy | 12.5 | — | 2010 | [c] | N/A |
| Guarantee the indemnification obligations of Seren under an asset purchase agreement | Xcel Energy | 20.0 | — | Continuing | [c] | N/A |
| Guarantee of customer loans for the Farm Rewiring Program | NSP-Wisconsin | 1.0 | 0.1 | Continuing | [e] | N/A |
| Combination of guarantees benefiting various Xcel Energy subsidiaries | Xcel Energy | 10.5 | — | Continuing | [b][c] | N/A |

(a) The total exposure of this indemnification cannot be determined. Xcel Energy believes the exposure to be significantly less than the total amount of the outstanding bonds.

(b) Nonperformance and/or nonpayment.

(c) Losses caused by default in performance of covenants or breach of any warranty or representation in the purchase agreement.

(d) Failure of Xcel Energy or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(e) The debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Xcel Energy agreed to indemnify an insurance company in connection with surety bonds they may issue or have issued for Utility Engineering up to $80 million. The Xcel Energy indemnification will be triggered only in the event that Utility Engineering has failed to meet its obligations to the surety company.

(g) See Note 15 to the consolidated financial statements for further discussion of Fru-Con Construction Corporation vs. Utility Engineering et al.

## Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2007 and 2006, there were $20.1 million and $43.8 million of letters of credit outstanding. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

## 14. Rate Matters

## NSP-Minnesota

### *Pending and Recently Concluded Regulatory Proceedings — MPUC*

### Base Rate

***NSP-Minnesota Natural Gas Rate Case*** — In November 2006, NSP-Minnesota filed a request with the MPUC to increase Minnesota natural gas rates by $18.5 million annually, or 2.4 percent. The request was based on an

11.0 percent ROE, a projected equity ratio of 51.98 percent and a natural gas rate base of $439 million. Interim rates, subject to refund, were set at a $15.9 million increase and went into effect on Jan. 8, 2007.

In September 2007, the MPUC issued an order approving a rate increase of approximately $11.9 million, based on an authorized ROE of 9.71 percent and an equity ratio of 51.98 percent. The MPUC subsequently denied NSP-Minnesota's request for rehearing on the ROE. NSP-Minnesota has filed a compliance filing and refund plan, proposing to implement final rates on Feb. 1, 2008. In January 2008, the MPUC approved the compliance filing.

***NSP-Minnesota Electric Rate Case*** — In November 2005, NSP-Minnesota requested an electric rate increase of $168 million or 8.05 percent. This increase was based on a requested 11 percent ROE, a projected common equity to total capitalization ratio of 51.7 percent and a projected electric rate base of $3.2 billion.

In September 2006, the MPUC issued an order approving a rate increase of approximately $131 million for 2006 based on an authorized ROE of 10.54 percent. This amount was reduced in 2007 to $115 million to reflect the return of Flint Hills Resources, a large industrial customer, to the NSP-Minnesota system. The MPUC order became effective in November 2006, and final rates were implemented on Feb. 1, 2007.

In March 2007, a citizen intervenor submitted a brief asking that the Minnesota Court of Appeals remand to the MPUC on various issues decided by the MPUC. The Court of Appeals issued an Order upholding the MPUC's decision.

## Electric, Purchased Gas and Resource Adjustment Clauses

***TCR*** — In November 2006, the MPUC approved a TCR rider pursuant to 2005 legislation. The TCR mechanism allows the recovery of incremental transmission investments between rate cases.

- NSP-Minnesota filed for approval of recovery of $14.7 million in 2007 under the TCR tariff.
- In March 2007, the MPUC approved recovery of $11.5 million in 2007.
- In August 2007, NSP-Minnesota filed for approval of recovery of $19.7 million in Minnesota retail electric rates in 2008 under the TCR tariff.
- In December 2007, NSP-Minnesota filed tariff sheets proposing to implement TCR rate factors that would recover only the non-disputed costs effective Jan. 1, 2008, subject to true up. In December 2007, the MDOC recommended 2008 recovery of approximately $18.5 million, asserting that certain costs did not meet statutory criteria. After further comment and reply, the parties resolved all disputed issues.
- The filing, as amended, is pending MPUC action.

***RES Rider*** — In June 2007, NSP-Minnesota filed an application for a new rate rider to recover the costs associated with utility-owned projects implemented in compliance with the RES adopted by the 2007 Minnesota legislature. The proposed rate adjustment would recover the costs associated with the Grand Meadow wind farm, a 100-MW wind project proposed by NSP-Minnesota. The rate rider would recover the 2008 revenue requirements associated with the project of approximately $14.6 million. MPUC action on this request is pending.

***Mercury Cost Recovery*** — In December 2006, NSP-Minnesota requested approval of a Mercury Emissions Reduction Rider to recover approximately $5.4 million during 2007 from Minnesota electric retail customers for costs associated with implementing both the mercury and other environmental improvement portions of the Mercury Emissions Reduction Act. NSP-Minnesota subsequently withdrew the filing and obtained approval to defer costs associated as a regulatory asset for potential future recovery. NSP-Minnesota has since filed a mercury reduction plan with the MPCA and MPUC and expects to file for rate rider recovery in the first half of 2008.

***Annual Automatic Adjustment Report for 2007*** — In September 2007, NSP-Minnesota filed its annual automatic adjustment report for July 1, 2006 through June 30, 2007, which is the basis for the MPUC review of charges that flow through the FCA and PGA mechanisms. During that time period, $1.16 billion in fuel and purchased energy costs, including $384 million of MISO Day 2 energy market charges were recovered from electric customers through the FCA. In addition, approximately $590 million of purchased natural gas and transportation costs were recovered through the PGA. The 2007 annual automatic adjustment report is pending comments and MPUC action.

## Other

***MISO Day 2 Market Cost Recovery*** — In December 2006, the MPUC issued an order ruling that NSP-Minnesota may recover all MISO Day 2 costs, except Schedules 16 and 17 administrative charges, through its fuel clause adjustment (FCA) effective April 1, 2005.

In April 2007, the MOAG filed an appeal of the MPUC order to the Minnesota Court of Appeals challenged the MPUC's decision to allow FCA recovery of these MISO charges. NSP-Minnesota and the other affected utilities intervened in the appeal and filed briefs urging the court to uphold the MPUC order. The oral argument in the appeal is scheduled for Feb. 27, 2008. The date for a court decision in the appeal is not known.

***Annual Review of Remaining Lives Depreciation Filing —*** In September 2007, the MPUC approved NSP-Minnesota's remaining lives depreciation filing effective to Jan. 1, 2007, lengthening the life of the Monticello nuclear plant by 20 years to 2030, as well as certain other smaller life adjustments. These adjustments reduced the depreciation expense of NSP-Minnesota by approximately $41 million for the period ended Dec. 31, 2007. The MPUC also approved an adjustment to rate base to be used in the next electric rate case that will hold ratepayers indifferent to this change in remaining lives between rate cases. NSP-Minnesota calculated the revenue requirement associated with this adjustment to be approximately $1.4 to $2.8 million, depending on the timing of the next electric rate case. In addition, the lengthening of the remaining life for the Monticello nuclear plant decreased the related ARO by $121 million in the third quarter of 2007 with no impact to net income in 2007.

***Nuclear Refueling Outage Costs —*** In November 2007, NSP-Minnesota filed a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request seeks approval to amortize refueling outage costs over the period between refueling outages to better match revenue and expenses. This request, if approved, would reduce 2008 expenses for NSP-Minnesota jurisdiction by $25 million due to deferral and amortization over an 18-month period versus expensed as incurred. Comparable filings have been made in North Dakota and South Dakota.

## *Pending Regulatory Proceedings — NDPSC and South Dakota Public Utilities Commission (SDPUC)*

***NSP-Minnesota North Dakota Electric Rate Case —*** In December 2007, NSP-Minnesota filed a request with the NDPSC to increase North Dakota retail electric rates by $20.5 million, or about 14 percent. The request was based on an 11.50 percent ROE, an equity ratio of 51.77 percent, and a jurisdictional rate base of approximately $242 million. Interim rates of $17.2 million became effective in February 2008. Hearings are expected to be held in late June, and final rates are expected to be effective Oct. 1, 2008. NSP-Minnesota and the NDPSC staff reached a stipulation settlement in the rate case in which both parties recommended an ROE of 10.75 percent, with a sharing mechanism for earnings about 10.75 percent. This stipulation settlement is subject to approval by the NDPSC.

## *Pending and Recently Concluded Regulatory Proceedings — FERC*

***FERC Transmission Rate Case*** — In September 2007, Xcel Energy and MISO filed proposed changes to the MISO TEMT to establish a revised formula transmission rate for the integrated NSP System. The rate filing would establish the transmission service rates for the NSP System based on annual forward looking (rather than historic) transmission costs; provide more current recovery of NSP System transmission investments, and allow recovery of certain transmission incentives authorized by the Energy Act and the implementation of FERC rules. Xcel Energy made the filing in anticipation of significant transmission capital additions by NSP-Minnesota and NSP-Wisconsin. A forward looking formula rate with a return on construction work in progress for major projects will facilitate the financing and construction of the new transmission facilities while providing a current return on invested capital for the portion of the investment subject to FERC rate jurisdiction. In December 2007, the FERC issued an order accepting the rate change effective Jan. 1, 2008, subject to Xcel Energy and MISO making certain changes to the procedures for pre-filing notice of the annual formula rate changes. No party filed for rehearing, and Xcel Energy submitted the required compliance filing on Jan. 22, 2008. The rate change is expected to increase 2008 NSP System transmission revenues by $2.7 million.

***MISO Long-Term Transmission Pricing*** — In October 2005, MISO filed a proposed change to its Open Access Transmission and Energy Markets Tariff (TEMT) to regionalize future cost recovery of certain high voltage transmission projects to be constructed for reliability improvements. The tariff, called the Regional Expansion Criteria Benefits phase I (RECB I) and a subsequent proposal based on regional economic benefits (RECB II), would recover varying percentages of eligible reliability transmission costs from all transmission service customers in the MISO 15 state region. In November 2006, the FERC issued an order accepting the RECB I tariff, including the 20 percent limitation. In December 2006, the PSCW and other parties filed an appeal of the RECB I order to the federal Court of Appeals for the District of Columbia. The appeal is pending.

In March 2007, the FERC issued an order approving most aspects of the RECB II proposal. Various parties filed requests for rehearing, which the FERC subsequently denied.

Transmission service rates in the MISO region presently use a rate design in which the transmission cost depends on the location of the load being served (referred to as "license plate" rates). Costs of existing transmission facilities are thus not regionalized. MISO and its transmission owners filed a successor rate methodology in August 2007, to be effective Feb. 1, 2008. Other entities sought to regionalize some of these costs. The impact of the regionalization of future facilities would depend on the specific facilities placed in service. In January 2008, the FERC issued an order accepting the MISO filing to continue use of license plate rates for existing facilities and RECB (limited regionalization) pricing for certain new facilities. The FERC rejected proposals to regionalize a larger share of the cost of existing or new transmission facilities.

***Revenue Sufficiency Guarantee Charges*** — In April 2006, the FERC issued an order determining that MISO had incorrectly applied its TEMT regarding the application of the revenue sufficiency guarantee (RSG) charge to certain transactions. The FERC ordered MISO to resettle all affected transactions retroactive to April 2005. The RSG charges are collected from MISO customers and paid to generators. In October 2006, the FERC issued an order granting rehearing in part and reversed the prior ruling requiring MISO to issue retroactive refunds and ordered MISO to submit a compliance filing to implement prospective changes.

In March 2007, the FERC issued orders separately denying rehearing of the FERC order. Several parties have filed separate appeals to the D.C. Circuit Court seeking judicial review of the FERC's determinations of the allocation of RSG costs among MISO market participants. Xcel Energy has intervened in each of these proceedings. In August 2007, Ameren Services Company (Ameren) and the Northern Indiana Public Service Company (NIPSCO) filed a joint complaint against MISO at the FERC, challenging the MISO's current FERC-approved methodology for the recovery of RSG costs. Subsequently, eight other entities filed complaints at the FERC effectively adopting the substantive arguments raised by Ameren and NIPSCO. In November 2007, the FERC issued an order that instituted a proceeding in these dockets to review evidence and to establish a RSG cost allocation methodology for market participants under the Midwest ISO Tariff. The refund-effective date established is Aug. 10, 2007. FERC action is pending.

## NSP-Wisconsin

## *Pending and Recently Concluded Regulatory Proceedings — PSCW*

### Base Rate

***Electric and Gas Rate Case*** — In June 2007, NSP-Wisconsin filed with the PSCW a request to increase retail electric rates by $67.4 million and retail natural gas rates by $5.3 million, representing overall increases of 14.3 percent and 3.3 percent, respectively. The request assumes a common equity ratio of 53.86 percent, a return on equity of 11.00 percent and a combined electric and natural gas rate base of approximately $640 million.

In January 2008, the PSCW issued the final written order, approving an electric rate increase of approximately $39.4 million, or 8.1 percent, and a natural gas rate increase of $5.3 million, or 3.3 percent. New rates went into effect Jan. 9, 2008. The PSCW approved or allowed for:

- A 10.75 percent return on equity.
- Reducing the PSCW staff's recommended common equity ratio from 53.58 percent to 52.5 percent.
- Recovery of NSP-Wisconsin's deferred nuclear decommissioning costs and the remaining deferred MISO Day 2 costs.
- A limited reopener for NSP-Wisconsin to propose recovery of production and transmission plant investment and associated operations and maintenance expenses as well as fuel costs for the year 2009.

A significant portion of PSCW staff adjustments were based on new or revised data since the filing was made, and will not have an earnings impact on NSP-Wisconsin. These adjustments, which total approximately $15 million, include:

- Increased revenues due to a higher than projected sales forecast ($6 million);
- Higher revenues associated with the interim fuel surcharge approved in October 2007 ($6 million);
- A lower forecast of fuel and purchased power costs than included in the original filing ($2 million); and
- A shift of DSM recovery from electric to gas operations ($1 million).

## Other

***2007 Electric Fuel Cost Recovery*** — In August 2007, NSP-Wisconsin filed an application with the PSCW requesting authorization to implement an electric fuel surcharge under the provisions of the Wisconsin fuel rules. The application requested authority to increase electric rates by $5.9 million or 1.3 percent on an annual basis. In October 2007, the PSCW issued an order approving an interim rate surcharge at the requested level, subject to refund. The interim rate surcharge became effective Oct. 15, 2007 and was terminated upon implementation of new base electric rates on Jan. 9, 2008. During the time period it was in effect, the surcharge generated approximately $1.3 million in additional revenue. Despite the additional surcharge revenue, NSP-Wisconsin's actual fuel costs for 2007 were approximately $11.9 million higher than fuel revenues recovered in rates. Factors contributing to the 2007 under recovery include the inherent limitations of the Wisconsin fuel rules, the PSCW's decision to set the initial 2007 fuel cost recovery factor at a lower level than requested by NSP-Wisconsin, and actual costs for the second half of 2007 that were higher than the level assumed in the forecast upon which the interim surcharge was based.

The PSCW is expected to review NSP-Wisconsin's actual 2007 fuel costs in the first quarter of 2008 to determine whether any refund of interim rates is necessary. Because actual 2007 fuel costs exceeded the amount recovered in rates, NSP-Wisconsin does not anticipate any refund will be required.

***Fuel Cost Recovery Rulemaking*** — In June 2006, the PSCW opened a rulemaking docket to address potential revisions to the electric fuel cost recovery rules. Wisconsin statutes prohibit the use of automatic adjustment clauses by large investor-owned electric public utilities. The statutes authorize the PSCW to approve, after a hearing, a rate increase for these utilities to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In August 2007, the PSCW staff issued its draft revisions to the fuel rules and requested comments. The draft rules are based largely on the original proposal submitted by the joint utilities, but incorporate the modifications requested by the PSCW. The proposed rules incorporate a plan year fuel cost forecast, deferred accounting for differences between actual and forecast costs (if the difference is greater than 2 percent), and an after the fact reconciliation proceeding to allow the opportunity to recover or refund the deferred balance. The PSCW did not take any official action on this rulemaking in 2007.

## PSCo

## *Pending and Recently Concluded Regulatory Proceedings — CPUC*

### Base Rate

***Natural Gas Rate Case*** — In December 2006, PSCo filed with the CPUC, a request to increase natural gas rates by $41.9 million, or 2.96 percent. The request assumed a common equity ratio of 60.17 percent, an ROE of 11 percent and a rate base of approximately $1.1 billion.

In July 2007, the CPUC approved with modifications a comprehensive settlement between PSCo, the CPUC staff, the OCC and Seminole Energy Services, LLC, providing for, among other things, the following:

- An annual revenue increase of $32.3 million, based on a 10.25 percent ROE and a 60.17 percent equity ratio.
- A modification to the partial decoupling mechanism to allow PSCo recovery of additional revenues in future years to compensate for the portion of the decline in weather normalized residential use per customer that exceeds the first 1.3 percent in annual decline in use (to be reflective of 50 percent of the historic average annual decline in use).

Final rates were implemented effective July 30, 2007. Under the provisions of this settlement, PSCo will be filing its Phase II (cost allocation and rate design) on or before March 31, 2008, to spread among PSCo's customer classes the settled revenue requirement from this case.

### Electric, Purchased Gas and Resource Adjustment Clauses

***Transmission Cost Adjustment Rider*** — In September 2007, PSCo filed with the CPUC a request to implement a transmission cost adjustment rider (TCA), which would recover approximately $18.2 million in 2008. This filing is pursuant to recently enacted legislation which entitled public utilities to recover, through a separate rate adjustment clause, the costs that it prudently incurs in planning, developing, and completing the construction or expansion of transmission. This legislation further encourages utilities to invest in transmission facilities by allowing the recovery of the total balance of construction work in progress related to those transmission investments at PSCo's weighted average cost of capital including its most recently authorized rate of ROE. The CPUC staff and certain other parties challenged the scope of PSCo's requested cost recovery under the rider during 2008.

In November 2007, PSCo updated its estimate of costs to be recovered through the TCA commencing Jan. 1, 2008, reducing its requested recovery during 2008 to $8.7 million.

In December 2007, the CPUC issued its initial decision approving PSCo's application to implement the TCA. The CPUC limited the scope of the costs that could be recovered through the rider during 2008 to only those costs associated with transmission investment made after the new legislation authorizing the rider became effective on March 26, 2007. The CPUC also will require PSCo to base its revenue requirement calculation on a thirteen month average net transmission plant balance. As a result of the CPUC's decision, PSCo will implement a rider on Jan. 1, 2008 to recover approximately $4.5 million in 2008. PSCo sought reconsideration of that aspect of the decision requiring it to base the rider on a thirteen-month average net transmission plant balance. In February, the CPUC voted to deny rehearing.

*Enhanced DSM Program* — In October 2007, PSCo filed an application with the CPUC for approval to implement an expanded DSM program and to revise its DSM cost adjustment mechanism (DSMCA) to include current cost recovery and incentives designed to reward PSCo for successfully implementing cost-effective DSM programs and measures. Under the DSM program currently in place, PSCo is committed to using its best efforts to acquire, on average, 40 MW of demand reduction and 100 GWh of energy savings per year from cost-effective DSM programs over the period beginning Jan. 1, 2006 and ending Dec. 31, 2013, so that by Jan. 1, 2014 PSCo will have achieved a cumulative level of 320 MW of total demand reduction and 800 GWh of annual energy savings. With this application, PSCo proposes to expand and extend its commitment to acquire a cumulative level of 694 MW of peak demand reduction and 2,351 GWh of energy savings, including achievements associated with its existing DSM programs over the period Jan. 1, 2009 through Dec. 31 2009. Under the proposed revision to the DSMCA, PSCo would recover 100 percent of its forecasted expenses associated with the DSM program during the year in which the rider is in effect as well as an incentive based upon the net economic benefits achieved during the prior year up to 20 percent of the net present vales of the benefits achieved.

*Interruptible Service Option Credit Program* — In November 2007, PSCo requested to expand its interruptible service option credit program (ISOC) to make it available to customers with interruptible demands of 300 KW and above. PSCo also seeks to change the basis upon which it pays credits to customers who participate in the program and to obtain approval for current recovery of those credits through the DSM Adjustment Clause. Lastly, PSCo seeks authority to recover an incentive in addition to receiving reimbursement of the credits paid to customers to reward it for successful implementation of a program that reduces overall costs to its retail customers. PSCo's petition is pending before the CPUC.

## *Pending and Recently Concluded Regulatory Proceedings — FERC*

*Pacific Northwest FERC Refund Proceeding* — In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been an active participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence regarding the use of certain strategies and how they may have impacted the markets in the Pacific Northwest markets. For the referenced period, parties have claimed that the total amount of transactions with PSCo subject to refund are $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the United States Court of Appeals for the Ninth Circuit.

In an order issued on Aug. 24, 2007, the Ninth Circuit issued an order remanding the proceeding back to the FERC. The court of appeals preliminarily determined that it had jurisdiction to review the FERC's decision not to order refunds and remanded the case back to the FERC, directing that the FERC consider evidence that had been presented regarding intentional market manipulation in the California markets and its potential ties to transactions in the Pacific Northwest. The court of appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets.

# SPS

## *Pending and Recently Concluded Regulatory Proceedings — PUCT*

### Base Rate

***Texas Retail Base Rate And Fuel Reconciliation Case*** — In May 2006, SPS filed a Texas retail electric rate case requesting an increase in annual revenues of approximately $48 million. The rate filing was based on a historical test year, an electric rate base of $943 million, a requested ROE of 11.6 percent and a common equity ratio of 51.1 percent.

In addition, SPS submitted a fuel reconciliation filing, which requested approval of approximately $957 million of Texas-jurisdictional fuel and purchased power costs for 2004 through 2005. As a part of the fuel reconciliation case, fuel and purchased energy costs were reviewed.

In March 2007, SPS and various intervenors filed a unanimous stipulation agreement related to the Texas retail rate case as well as the fuel reconciliation portion of the proceeding. An estimated settlement allowance and reserve was established in 2006 and prior periods, which approximated the settled amounts of previously deferred or recovered fuel expense.

In July 2007, the PUCT issued a written order adopting the settlement and determined that SPS' sale to EPE should be assigned incremental cost. Included in the order are the following decisions:

- An annual base rate increase of $23 million, or approximately 3 percent.
- Disallowed approximately $27 million of SPS' 2004 and 2005 fuel expense.
- An additional $2.3 million will be deducted from SPS' next fuel reconciliation filing to be made in 2008, associated with the 2006-2007 fuel reconciliation period.
- All of SPS' existing long-term firm and interruptible capacity wholesale sales are assigned system average costs for purposes of Texas retail ratemaking, except for sales to El Paso Electric (EPE), which is assigned incremental costs to the EPE sale. The effect of this decision under the terms of the settlement is a continuation of incremental fuel assignment for the sale to EPE in 2007, a portion of which SPS will not recover either through its FCA or its contract. For 2008, this amount will be $6.3 million
- Established a standard for cost assignment that would apply to future wholesale sale transactions, and establishes margin sharing of market based wholesale demand revenues.
- If SPS files a general rate case in 2008, the settlement would allow for an interim rate increase associated with a purchased power agreement with Lea Power Partners of approximately $1.5 million per month from the date of commercial operations. Interim rates would be subject to a true-up based on the outcome of the rate case proceeding and actual capacity costs incurred.

SPS has previously given notice to EPE to terminate the agreement based on a regulatory provision and Xcel Energy has reached agreement with EPE that the termination will be effective Sept. 30, 2009. SPS plans to file in mid-2008, another Texas retail base rate case and application to reconcile its 2006 and 2007 fuel costs.

***Application to Increase Voltage-Level Line Loss Factors*** — In June 2007, SPS filed for approval of an increase in its voltage level line-loss factors. On Jan. 31, 2008, the PUCT approved SPS' application to update its current Texas retail fuel. Under the Texas Retail Base Rate case discussed above, SPS is permitted to implement the revised line loss factors effective to May 2007. SPS recognized $6.2 million in the fourth quarter of 2007 for the impact of the study from May 1, 2007 through Dec. 31, 2007.

### Electric and Resource Adjustment Clauses

***TCR Factor Rulemaking*** — The PUCT adopted in November 2007 new rules relating to TCR Factor outside of a base rate case. The rule establishes the mechanism by which SPS can request annual recovery of its reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges that are not included in existing rates. This new rule allows SPS more timely recovery of transmission cost increases in-between base rate cases.

## *Pending and Recently Concluded Regulatory Proceedings — NMPRC*

### Base Rate

***New Mexico Electric Rate Case*** — In July 2007, SPS filed with the NMPRC requesting a New Mexico retail electric general rate increase of $17.3 million annually, or a 6.6 percent increase. The rate filing is based on a 2006 calendar year base period adjusted for known and measurable changes and includes a requested rate of return on equity of 11.0 percent, an electric rate base of approximately $307.3 million and an equity ratio of 51.2 percent.

- The NMPRC suspended the requested effective date for an additional 12 months beyond the requested effective date, the maximum permitted under New Mexico law.
- Intervenor testimony is due in March 2008, and hearings are scheduled for April 2008.
- The hearing examiner is requested to issue a recommendation by June 30, 2008.
- A decision on the request is expected in the third quarter of 2008, and final rates are expected to be implemented by Aug. 29, 2008.

## Electric and Resource Adjustment Clauses

***New Mexico Fuel Factor Continuation Filing*** — In August 2005, SPS filed with the NMPRC requesting continuation of the use of SPS' fuel and purchased power cost adjustment clause (FPPCAC) and current monthly factor cost recovery methodology. This filing was required by NMPRC rule.

Testimony was filed in the case by staff and intervenors objecting to SPS' assignment of system average fuel costs to certain wholesale sales and the inclusion of certain purchased power capacity and energy payments in the FPPCAC. The testimony also proposed limits on SPS' future use of the FPPCAC. Related to these issues some intervenors requested disallowances for past periods, which in the aggregate total approximately $45 million. This claim was for the period from Oct. 1, 2001 through May 31, 2005 and does not include the value of incremental cost assigned for wholesale transactions from that date forward. Other issues in the case include the treatment of renewable energy certificates and $SO_2$ allowance credit proceeds in relation to SPS' New Mexico retail fuel and purchased power recovery clause.

In December 2007, SPS, the NMPRC, Occidental Permian Ltd. and the New Mexico Industrial Energy Consumers (NMIEC) filed an uncontested settlement of this matter with the NMPRC.

- The settlement resolves all issues in the fuel continuation proceeding for total consideration of $15 million.
- The amounts include resolution of all system average fuel matters through Dec. 31, 2007 with a refund to customers of $11.7 million.
- Resolution of issues related to capacity costs and $SO_2$ allowances resulting in refunds totaling $1.8 million.
- A commitment to fund low-income energy efficiency programs in 2008 and 2009 and invest in a solar project all at a total cost of $1.5 million.
- At Dec. 31, 2007, a reserve had been previously established for this potential exposure, with no further expense accrual required, assuming this settlement is approved.
- The settlement would also resolve certain affiliate transactions raised by the parties, provide for significantly greater certainty surrounding system average fuel cost assignment on a going forward basis and reduce percentages of system average cost wholesale sales between now and 2019 on a stepped down basis.
- Under the terms of the settlement, SPS anticipates additional fuel cost disallowances in 2008 and a portion of 2009 of approximately $2 million per year. It does not anticipate any future disallowances beyond this period.
- The settlement would eliminate the need for any future proceedings related to wholesale contracts in effect in 2006 and beyond, and affiliate transactions dating back to the merger creating Xcel Energy in 2000, as would have been required under the hearing examiner's recommended decision.
- Finally, the settlement provides for SPS to continue its use of the FPPCAC subject to additional reporting provisions.

Because New Mexico procedures traditionally require a hearing on any proposed settlement, the parties to the settlement have jointly requested that the settlement be remanded back to the ALJ for such hearings before being taken up by the NMPRC. In January 2008, the NMPRC issued an order remanding the proceeding to the hearing examiner. A hearing on the settlement has been set for April 2008.

## Other

***Investigation of SPS Participation in SPP*** — In October 2007, the NMPRC issued an order initiating an investigation to consider the prudence and reasonableness of SPS' participation in the SPP RTO. The investigation will consider the costs and benefits of RTO participation to SPS customers in New Mexico. The order required SPS to file direct testimony no later than 75 days after the completion of the hearing in the New Mexico electric rate case.

***Investigation into the Reasonableness of Executive Compensation*** — In December 2007, the NMPRC initiated an investigation into executive compensation of investor-owned electric and natural gas utilities serving within the state. SPS is required to report executive and board compensation levels for the past 30 years.

## *Pending and Recently Concluded Regulatory Proceedings — FERC*

***Wholesale Rate Complaints*** — In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer's Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS' rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustments contained in SPS' wholesale rate schedules (the Complaint). Among other things, the complainants asserted that SPS was not properly calculating the fuel costs that are eligible for recovery and that SPS had inappropriately allocated average fuel and purchased power costs to its other wholesale customers, effectively raising the fuel cost charges to complainants. Additionally, the Complaint alleged that the base rates being charged were too high and that the FERC should act to lower SPS' customers' rates. Cap Rock Energy Corporation (Cap Rock), a full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS' largest retail customer, intervened in the proceeding.

In May 2006, a FERC administrative law judge (ALJ) issued an initial recommended decision in the proceeding. In the recommended decision, the ALJ found that SPS should recalculate its wholesale fuel and purchased economic energy cost adjustment clause (FCAC) billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by allocating incremental fuel costs incurred by SPS in making wholesale sales of system firm capacity and associated energy to other firm customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales. In addition, the ALJ made recommendations on a number of base rate issues including a 9.64 percent ROE and the use of a 3-month coincident peak (3CP) demand allocator. The FERC will review the ALJ's recommended decisions and issue a final order, which may or may not follow any of the ALJ's recommendation.

SPS believes the ALJ erred on significant and material issues that contradict FERC policy or rules of law. Specifically, SPS believes, based on FERC rules and precedent, that it has appropriately applied its FCAC tariff to the proper classes of customers. These firm market-based sales were of a long-term duration under FERC precedent and were made from SPS' entire system. Accordingly, SPS believes that the ALJ erred in concluding that these transactions were opportunity sales, which require the assignment of incremental costs.

The FERC has approved system average cost allocation treatment in previous filings by SPS for sales having similar service characteristics and previously accepted for filing certain of the challenged agreements with average fuel cost pricing.

Moreover, SPS believes that the ALJ's recommendation constituted a violation of the filed rate doctrine in that it effectively results in a retroactive amendment to the SPS FERC-approved FCAC tariff provisions. Under existing regulations, the FERC may modify a previously approved FCAC on a prospective basis. Accordingly, SPS believes it has applied its FCAC correctly and has sought review of the recommended decision by the FERC by filing a brief on the exceptions.

SPS believes it should ultimately prevail in this proceeding; however, if the FERC were to adopt the majority of the ALJ's recommendations, SPS' refund exposure, including Golden Spread, could be approximately $50 million, based on an evaluation of all sales made from Jan. 1, 1999 to Dec. 31, 2006. This estimate is based upon sales to wholesale customers of SPS that had been customers for less than five years and assumes that the FERC would not assign incremental fuel cost to agreements with longstanding customers to whom SPS has assigned system average fuel costs for many years. If the FERC were to assign incremental fuel costs to longstanding customers, SPS' exposure could exceed $50 million.

SPS has reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. If the Settlement is approved, any potential exposure faced by SPS for fuel cost disallowances in the Complaint proceeding would be reduced by approximately 40 percent, Golden Spread's relative proportion of energy delivered during the period.

The Settlement seeks approval of:

- A $1.25 million payment by SPS to Golden Spread related to potential damage claims Golden Spread may have associated with the quantities they are entitled to take under the existing partial requirements agreement for the years 2006 and 2007. The Settlement caps those quantities for the period 2008 through 2011. SPS is not required to make any fuel refunds to Golden Spread that were the subject of the Complaint under the terms of the Settlement.

- An extended partial requirements contract at system average cost, with a capacity amount that ramps down over the period 2012 through 2019 from 500 MW to 200 MW. The extended agreement requires that the cost assignment treatment receive Texas and New Mexico state approvals and provides for alternative pricing terms and quantities to hold SPS harmless from cost disallowances in the event that adverse regulatory treatment occurs or state approvals are not obtained. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals.
- Resolution of base rates in the Complaint without any adjustment to the existing rates for the period January 2005 through June 30, 2006. The Settlement also resolves all base rate issues in SPS' rate case application for the period July 1, 2006 through June 30, 2008 other than the three month coincident peak (3 CP) or 12 month coincident peak (12CP) method of allocation of demand related costs and sets forth two sets of agreed on rates that are dependent on the ultimate resolution of that issue. If SPS prevails in its support of the 12 CP demand allocation method, there would be no impact to earnings for this period. If Golden Spread prevails, SPS would be required to refund Golden Spread and PNM approximately $4 million for the period through the end of 2007.
- For July 1, 2008 and beyond, Golden Spread will be under a formula rate for production plant, similar to a formula rate for transmission investment. The rate will be based on the most recent historic year actuals adjusted for known and measurable changes and trued up to the actual performance in a calendar year. The formula will begin based on a 10.25 percent ROE and either party will have a right to seek changes to the ROE beginning with the 2009 formula rate filing. SPS will share margins from its sales to WTMPA and EPE in that year but will assign system average fuel and energy costs to those agreements for purposes of calculating Golden Spread's monthly fuel cost.

The Settlement is subject to approval by the FERC; however, no parties contested the Settlement. SPS does not expect to settle with all parties to the Complaint and expects the FERC to issue an order addressing the ALJ's recommended decision and all aspects of the Complaint. The FERC could issue the order with respect to non-settling parties, prior to taking action on the Settlement. As of December 2007, based upon the expectation that the Golden Spread settlement is approved and offers made to the various parties in the Complaint, SPS believes the appropriate accrual has been recorded for this matter.

***Wholesale 2005 Power Base Rate Application*** — In December 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. In January 2006, the FERC conditionally accepted the proposed rates for filing and the $2.5 million power rate increase became effective on July 1, 2006, subject to refund. The FERC also set the rate increase request for hearing and settlement judge procedures. In September 2006, offers of settlement with respect to the five full-requirements customers and with respect to PNM were filed for approval. In September 2007, the FERC accepted the settlement with the full-requirements customers. The PNM settlement is still pending before the FERC.

The Wholesale 2005 Power Base Rate Application relating to Golden Spread was settled in conjunction with the Wholesale Rate Complaint Settlement discussed above. Therefore, SPS has settled with all parties in the Wholesale 2005 Power Base Rate Application except for with respect to the 3 CP/12 CP demand allocation methodology discussed above.

***SPS Formula Transmission Rate Case*** — In December 2007, Xcel Energy submitted an application to implement a transmission formula rate for the SPS zone of the Xcel Energy OATT. The SPP made a companion filing in January 2008, to implement the same pricing in the SPS zone of the SPP regional OATT. The changed rates will affect all wholesale transmission service customers using the SPS transmission network under either the SPP Regional OATT or the Xcel Energy OATT.

SPS made the filing in anticipation of approximately $290 million of transmission capital additions from 2008 to 2012. A formula rate will help facilitate the financing and construction of the new transmission facilities while providing an adequate rate of return on invested capital. The proposed rates would be updated annually each July 1st based on SPS' prior year actual costs and loads plus the revenue requirements associated with projected current year transmission plant additions. The proposed rate of return on common equity is 12.7 percent, including a 50 basis point adder for SPS' participation in the SPP RTO, consistent with FERC precedent. The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC issued an order accepting the proposed rates, suspending the effective date to July 6, 2008, and setting the rate filing for hearings and settlement procedures. The FERC granted a 50 basis point adder to the rate of return on common equity that it will determine in this proceeding as a result of SPS' participation in the SPP regional transmission organization. The FERC has not yet acted on the companion SPP rate change filing. The ultimate outcome of the rate filings is not known at this time.

## 15. Commitments and Contingent Liabilities

### Commitments

***Capital Commitments*** — The estimated cost as of Dec. 31, 2007 of capital requirements of Xcel Energy and its subsidiaries and the capital expenditure programs is approximately $2.1 - $2.2 billion in 2008, $1.8 - $2.0 billion in 2009 and $1.9 - $2.1 billion in 2010. Xcel Energy's capital forecast includes the following major projects:

*CAPX 2020* — In June 2006, CapX 2020, an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest, including Xcel Energy, announced that it had identified several groups of transmission projects that proposed to be complete by 2020. Group 1 project investments are expected to total approximately $1.3 billion, with major construction targeted to begin in 2009 or 2010 and ending three or four years later. Xcel Energy's investment is expected to be approximately $700 million. Approximately 75 percent of the capital expenditures and return on investment for transmission projects are expected to be recovered under an NSP-Minnesota TCR tariff rider mechanism authorized by Minnesota legislation, as well as similar TCR mechanisms passed in North Dakota and South Dakota. Cost recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

*Nuclear Capacity Increases and Life Extension* — In August 2004, NSP-Minnesota announced plans to pursue 20-year license renewals for the Monticello and Prairie Island nuclear plants, whose licenses will expire between 2010 and 2014. License renewal for Monticello was approved by the NRC in November 2006 and the MPUC issued its approval in October 2006 allowing additional spent fuel storage. Similar applications will be submitted for Prairie Island in 2008, with final state and federal approvals expected in 2010.

NSP-Minnesota is pursuing capacity increases of all three units that will total approximately 230 MW, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2's original steam generators, currently planned for replacement during the refueling outage in 2013. Total capital investment for these activities is estimated to be approximately $1 billion between 2006 and 2015. NSP-Minnesota plans to seek approval for an alternative recovery mechanism from customers of its nuclear costs. It is NSP-Minnesota's plan to submit the certificate of need for Monticello in the first quarter of 2008 and the certificate of need for Prairie Island in the second quarter of 2008.

*MERP Project* — In December 2003, the MPUC approved NSP-Minnesota's MERP proposal to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. Major construction for the MERP project began in 2005 and these projects are expected to come on line between 2007 and 2009. The cumulative investment is approximately $1 billion. The MPUC has approved a more current recovery of the financing costs related to the MERP. The in-service plant costs, including the financing costs during construction, are recovered from customers through a MERP rider, which was effective Jan. 1, 2006.

*Comanche 3* — Comanche 3, a 750 MW coal-fired plant being built in Colorado, is expected to cost approximately $1.35 billion, with major construction initiated in 2006 and completed in the fall of 2009. The CPUC has approved sharing one-third ownership of this plant with other parties. Consequently, PSCo's investment in Comanche 3 will be approximately $1 billion.

*Sherco Project* — NSP-Minnesota has proposed a $1.1 billion upgrade at the Sherco coal-fired power plant. The project will increase capacity and reduce emissions. The MPUC is expected to rule on the project in 2008. If approved, construction would start in late 2010 and be completed on the final unit in 2014.

*Wind Generatio*n — NSP-Minnesota plans to invest $213 million to acquire 100-MW of wind generation. The project would be eligible for rider recovery in Minnesota. The project received approval by the MPUC in December 2007.

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 regulatory decisions, 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 compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

***Leases*** — Xcel Energy and its subsidiaries lease a variety of equipment and facilities used in the normal course of business. Two of these leases qualify as capital leases and are accounted for accordingly. The capital leases contractually expire in 2025 and 2028. The assets and liabilities acquired under capital leases are recorded 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.

Following is a summary of property held under capital leases:

| | 2007 | 2006 |
|---|---|---|
| | (Millions of Dollars) | |
| Storage, leaseholds and rights | $ 40.5 | $ 40.5 |
| Gas pipeline | 20.7 | 20.7 |
| | 61.2 | 61.2 |
| Accumulated amortization | (16.3) | (15.0) |
| Total property held under capital leases | $ 44.9 | $ 46.2 |

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, cars and power-operated equipment, are accounted for as operating leases. Rental expense under operating lease obligations for Xcel Energy and its subsidiaries was approximately $105.2, $60.3 million and $57.2 million for 2007, 2006 and 2005, respectively. Purchase power agreements contributed $55.7 million and $14.5 million in 2007 and 2006, respectively.

Included in the future commitments under operating leases are estimated future payments under purchase power agreements that have been accounted for as operating leases in accordance with Emerging Issues Task Force 01-8, "*Determining whether an Arrangement Contains a Lease*" and SFAS No. 13, "*Accounting for Leases*." Future commitments under operating and capital leases for continuing operations are:

| | Other Operating Leases | Purchase Power Agreement Operating Leases | Total Operating Leases | Capital Leases |
|---|---|---|---|---|
| | | (Millions of Dollars) | | |
| 2008 | $28.0 | $ 76.6 | $104.6 | $ 6.1 |
| 2009 | 25.1 | 77.5 | 102.6 | 6.0 |
| 2010 | 23.2 | 74.2 | 97.4 | 5.8 |
| 2011 | 20.4 | 64.0 | 84.4 | 5.7 |
| 2012 | 16.9 | 60.5 | 77.4 | 5.5 |
| Thereafter | 55.9 | 916.6 | 972.5 | 56.9 |
| Total minimum obligation | | | | 86.0 |
| Interest component of obligation | | | | (41.1) |
| Present value of minimum obligation | | | | $ 44.9 |

***Technology Agreement*** — Xcel Energy has a contract that extends through 2015 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. In 2007, Xcel Energy paid IBM $126.2 million under the contract and $0.4 million for other project business. The contract also has a committed minimum payment each year from 2008 through September 2015. Payments under this obligation are $21.6 million, $20.4 million, $20.0 million, $19.6 million, $19.4 million and $52.5 million for 2008 to 2012 and thereafter, respectively.

***Fuel Contracts*** — Xcel Energy and its subsidiaries have 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 2008 and 2033. In total, Xcel Energy is committed to the minimum purchase of approximately $3.2 billion of coal, $475.7 million of nuclear fuel and $4.8 billion of natural gas, including $3.4 billion of natural gas storage and 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 use of natural gas and energy cost rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

***Purchased Power Agreements*** — The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Certain contractual payment obligations are adjusted based on indices. However, the effects of price adjustments are mitigated through cost-of-energy rate adjustment mechanisms.

Xcel Energy has also executed five additional purchase power agreements that are conditional upon achievement of certain conditions, including becoming operational. Estimated payments under these conditional obligations are $52.8 million, $82.7 million, $83.0 million, $83.4 million, $94.5 million and $1.7 billion for 2008 to 2012 and thereafter, respectively.

At Dec. 31, 2007, the estimated future payments for capacity, accounted for as executory contracts, that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

| | (Millions of Dollars) |
|---|---|
| 2008 | $ 496.7 |
| 2009 | 479.2 |
| 2010 | 452.3 |
| 2011 | 438.7 |
| 2012 | 365.1 |
| 2013 and thereafter | 1,354.9 |
| Total | $3,586.9 |

## Environmental Contingencies

Xcel Energy and its subsidiaries have been, or are currently involved with, the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

***Site Remediation*** — Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries and some other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including the following categories of sites:

- Sites of former manufactured gas plants (MGPs) operated by Xcel Energy subsidiaries, predecessors, or other entities; and
- Third-party sites, such as landfills, to which Xcel Energy is alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes.

Xcel Energy records a liability when enough information is obtained to develop an estimate of the cost of environmental remediation and revises the estimate as information is received. The estimated remediation cost may vary materially from the initial estimate.

To estimate the remediation cost for these sites, assumptions are made when facts are not fully known. For instance, assumptions may be made 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.

Estimates are revised as facts become known. At Dec. 31, 2007, the liability for the cost of remediating these sites was estimated to be $46.9 million, of which $2.5 million was considered to be a current liability. 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. Estimates have been recorded for Xcel Energy's future costs for these sites.

*Manufactured Gas Plant Sites*

***Ashland Manufactured Gas Plant Site*** — NSP-Wisconsin was named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill and an area of Lake Superior's Chequemegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A determination of the scope and cost of the remediation of the Ashland site is not currently expected until late 2008 following the submission of the feasibility study in October 2007. NSP-Wisconsin continues to work with the Wisconsin Department of Natural Resources (WDNR) to access state and federal funds to apply to the ultimate remediation cost of the entire site. In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) Program accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007 and the EPA is scheduled to complete its assessment in early 2008. In 2007, NSP-Wisconsin spent $1.5 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. In June 2007, the EPA modified its remedial investigation report to establish final remedial action objectives (RAOs) and preliminary remediation goals (PRGs) for the Ashland site. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup. In September 2007, the EPA approved the series of reports included in the remedial investigation (RI) report. The draft feasibility study, which develops and assesses the alternatives for cleaning up the site, was prepared by NSP-Wisconsin and was submitted to the EPA in October 2007. The range of remediation costs set forth in the draft feasibility study is between $35.8 million and $125.5 million. In February 2008, the EPA provided written comments on the October 2007 draft feasibility study submitted by NSP-Wisconsin. NSP-Wisconsin has until April 2, 2008 to submit a revised draft feasibility study based upon the EPA's comments.

In October 2004, the WDNR filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The lawsuit has been stayed. NSP-Wisconsin has recorded an estimate of its potential liability. All costs paid to the WDNR are expected to be recoverable in rates.

In addition to potential liability for remediation and WDNR oversight costs, NSP-Wisconsin may also have liability for natural resource damages (NRD) at the Ashland site. NSP-Wisconsin has indicated to the relevant natural resource trustees its interest in engaging in discussions concerning the assessment of natural resources injuries and in proposing various restoration projects in an effort to fully and finally resolve all NRD claims. NSP-Wisconsin is not able to estimate its potential exposure for NRD at the site, but has recorded an estimate of its potential liability based upon the minimum of its estimated range of potential exposure.

Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin's level of responsibility, NSP-Wisconsin's liability for the actual cost of remediating the Ashland site is not determinable. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, that portion of the recorded liability related to remediation is based upon the minimum of the estimated range of remediation costs, contained in the draft feasibility study. NSP-Wisconsin has recorded a liability of $43.8 million for its potential liability related to the Ashland site, including potential liability for remediation of the Ashland site, WDNR, oversight costs and NRD, outside legal and consultant costs and work plan costs.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for MGP-related 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. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers.

***Fort Collins Manufactured Gas Plant Site*** — Prior to 1926, the Poudre Valley Gas Co. operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the assets of the Poudre Valley Gas Co., PSCo shut down the MGP site and has subsequently sold most of the property. In 2002, an oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. In November 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co. under which PSCo performed remediation and monitoring work. PSCo has substantially completed work at the site, with the exception of ongoing maintenance and monitoring.

In May 2005, PSCo filed a natural gas rate case with the CPUC requesting recovery of cleanup costs at the Fort Collins MGP site spent through March 2005, which amounted to $6.2 million, to be amortized over four years. PSCo reached a settlement agreement with the parties in the case. In January 2006, the CPUC approved the settlement agreement and rates were effective Feb. 6, 2006.

In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional clean-up costs at the Fort Collins MGP site spent through September 2006, plus unrecovered amounts previously authorized from the last rate case, which amounted to $10.8 million to be amortized over four years. In June 2007, PSCo entered into a settlement agreement that included recovery of the full $10.8 million, but with a five year amortization period. The CPUC approved the agreement on June 18, 2007. The total amount to be recovered from customers is $13.1 million. Estimated future project costs, based upon an assumed 30-year system operating life, including EPA oversight costs, are approximately $3.9 million.

In April 2005, PSCo brought a contribution action against Schrader Oil Co. and related parties alleging Schrader Oil Co. released hazardous substances into the environment and these releases caused MGP byproducts to migrate to the Cache la Poudre River, thereby substantially increasing the scope and cost of remediation. PSCo requested damages, including a portion of the costs PSCo incurred to investigate and remove contaminated sediments from the Cache la Poudre River. In December 2005, the court denied Schrader's request to dismiss the PSCo suit. Schrader thereafter filed a response to the PSCo complaint and a counterclaim against PSCo for its response costs under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and under the Resource Conservation and Recovery Act (RCRA). Schrader alleged as part of its counterclaim an "imminent and substantial endangerment" of its property as defined by RCRA. PSCo filed a motion for partial summary judgment to dismiss Schrader's RCRA claim. In October 2007, the court granted PSCo's motion for partial summary judgment and dismissed Schrader's RCRA claim. Schrader also filed a motion for summary judgment seeking to dismiss PSCo's CERCLA claim. PSCo believes this motion is without merit and will vigorously defend its claim. Any costs recovered from Schrader are expected to operate as a credit to ratepayers.

***Third Party and Other Environmental Site Remediation***

***Asbestos Removal*** — Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an ARO.

See additional discussion of AROs in Note 15 in the consolidated financial statements included below. 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.

***Cunningham and Maddox Station Groundwater*** — Cunningham Station is a natural gas-fired power plant constructed in the 1960s by SPS and has 28 water wells installed on its water rights. The well field provides boiler makeup, cooling and potable water. Following an acid release in 2002, groundwater samples revealed elevated concentrations of inorganic salt compounds not related to the release. The contamination was identified in wells located near the plant buildings and the source of contamination is thought to be leakage from ponds that receive blow down water from the plant.

In response to a request by the New Mexico Environment Department (NMED), SPS prepared a corrective action plan to address the groundwater contamination. Under the plan submitted to the NMED, SPS agreed to control leakage from the plant blow down ponds through construction of a new lined pond, additional irrigation areas to minimize percolation and installation of additional wells to monitor groundwater quality. In June 2005, NMED issued a letter approving the corrective action plan. The action plan was subject to continued compliance with New Mexico regulations and oversight by the NMED. The Cunningham wastewater management project has been completed at a final cost of $3.5 million. Upon completion of the project, NMED finalized the wastewater permit. SPS began the implementation of a similar process at the Maddox Station in 2007. The permitting process for Maddox Station has begun and is estimated to cost approximately $1.3 million through 2008 and will be capitalized or expensed as incurred.

***Other Environmental Requirements***

***CAIR*** — In March 2005, the EPA issued the CAIR to further regulate $SO_2$ and NOx emissions. The objective of CAIR is to cap emissions of $SO_2$ and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy's service territory. Xcel Energy generating facilities in other states are not affected. CAIR addresses the transportation of fine particulates, ozone and emission precursors to nonattainment downwind states. CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for $SO_2$, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for $SO_2$ and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA's proposed model program, or they can propose another method, which the EPA would need to approve.

In July 2005, SPS, the City of Amarillo, Texas and Occidental Permian LTD filed a lawsuit against the EPA and a request for reconsideration with the agency to exclude West Texas from the CAIR. El Paso Electric Co. joined in the request for reconsideration. Xcel Energy and SPS advocated that West Texas should be excluded from CAIR because it does not contribute significantly to nonattainment with the fine particulate matter standards in any downwind jurisdiction.

In March 2006, the EPA denied the petition for reconsideration and in June 2006, Xcel Energy and the other parties filed a petition for review of the denial of the petition for reconsideration, as well as a petition for review of the Federal Implementation Plan, with the D.C. Court of Appeals. Briefing has now been finalized, and oral argument is scheduled for March 2008.

Under CAIR's cap-and-trade structure, SPS can comply through capital investments in emission controls or purchase of emission "allowances" from other utilities making reductions on their systems. Based on the preliminary analysis of various scenarios of capital investment and allowance purchase, Xcel Energy currently believes that after the installation of low NOx burners on Harrington 3 in 2006, the remaining capital investments for NOx controls in the SPS region are estimated at $12 million. Purchases of NOx allowances in the first phase are estimated at $8.9 million. Annual purchases of $SO_2$ allowances are estimated in the range of $13 million to $25 million each year, beginning in 2012, for phase I, based on allowance costs and fuel quality as of March 2007. These cost estimates represent one potential scenario on complying with CAIR, if West Texas is not excluded.

In addition, Minnesota and Wisconsin will be included in CAIR, and Xcel Energy has generating facilities in these states that will be impacted. Preliminary estimates of capital expenditures associated with compliance with CAIR in Minnesota and Wisconsin range from $30 million to $40 million. Xcel Energy is not challenging CAIR in these states.

While Xcel Energy expects to comply with the new rules through a combination of additional capital investments in emission controls at various facilities and purchases of emission allowances, it is continuing to review the alternatives. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

***CAMR*** — In March 2005, the EPA issued CAMR, which regulated mercury emissions from power plants. On Feb. 8, 2008, the D.C. Circuit Court of Appeals vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. Costs to comply with the Minnesota Mercury Emissions Reduction Act of 2006 are discussed below.

In Colorado, the Air Quality Control Commission passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at Pawnee Station by 2012 and all other Colorado units by 2014. Xcel Energy is in the process of installing mercury monitors on seven Colorado units at an estimated aggregate cost of approximately $2.6 million. Xcel Energy is evaluating the emission controls required to meet the new rule and is currently unable to provide a capital cost estimate.

In the SPS region, the Texas Commission on Environmental Quality (TCEQ) adopted by reference the EPA model program Given the many uncertainties created by decision of the D.C. Circuit Court of Appeals to vacate the CAMR, it is not possible at this time to provide an accurate summary of applicable federal mercury requirements or cost estimates.

***Minnesota Mercury Legislation*** — In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For Xcel Energy, the Act covers units at the A. S. King and Sherco generating facilities. Under the Act, Xcel Energy is operating and maintaining continuous mercury emission monitoring systems. The information obtained will be used to establish a baseline from which to measure mercury emission reductions. Mercury emission reduction plans were required to be filed by utilities by Dec. 31, 2007 (dry scrubbed units) and Dec. 31, 2009 (wet scrubbed units) that propose to implement technologies most likely to reduce emissions by 90 percent. Implementation would occur by Dec. 31, 2009 for one of the dry scrubbed units, Dec. 31, 2010 for the remaining dry scrubbed unit and Dec. 31, 2014 for wet scrubbed units. The cost of controls will be determined as part of the engineering analysis portion of the mercury reduction plans and is currently estimated to range from $26.5 to $854.5 million for the mercury control and continuous monitoring equipment for Sherco units 1, 2 and 3 and for A.S. King, with increased operating and maintenance expenses estimated to range from approximately $24.7 to $77.2 million. The lower values include costs to achieve a 50 percent mercury reduction for Sherco units 1 and 2 and a 90 percent mercury reduction for Sherco unit 3 and A. S. King. The higher values include costs to achieve a 90 percent mercury reduction for all Sherco units, as well as for A. S. King. Utilities subject to the Act may also submit plans to address non-mercury pollutants subject to federal and state statutes and regulations, which became effective after Dec. 31, 2004. Cost recovery provisions of the Act also apply to these other environmental initiatives. In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs that are expected to be recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. To date NSP-Minnesota has spent approximately $1.3 million on mercury monitoring implementation.

***Regional Haze Rules*** — In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements. Some of these facilities are located in regions where CAIR is effective. CAIR has precedence over BART. Therefore, BART requirements will be deemed to be met through compliance with CAIR requirements.

The EPA required states to develop implementation plans to comply with BART by December 2007. States are required to identify the facilities that will have to reduce $SO_2$, NOx, and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART technology or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of the BART alternatives will cost approximately $211 million in capital costs, which includes approximately $62 million in environmental upgrades for the existing Comanche Station project, which are included in the capital budget. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2011 and 2014. On June 4, 2007, the CAPCD approved PSCo's BART analysis and obtained public comment on its BART determination and PSCo's BART permits. The Air Quality Control Commission (AQCC) approved the CAPCD's BART determination for PSCo during a public hearing in December 2007. CAPCD's BART determinations and corresponding provisions of the regional haze state implementation plan will be submitted to the EPA for approval in 2008. In addition, in early 2008, the CAPCD plans to embark on a stakeholder process to develop presumptive standards for significant source categories and establish reasonable progress goals for Colorado's Class I areas. To meet these goals, more controls may be required from certain sources, which may or may not include those sources previously controlled under BART.

NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. At this time, the MPCA is not requiring any BART specific controls that go beyond controls required for CAIR compliance.

***Voluntary Capacity Upgrade and Emissions Reduction Filing*** — In December 2007, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco Units 1and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1 billion and encompasses the higher value mercury control costs discussed above in the Minnesota Mercury Legislation section. The filing also contains alternatives for the MPUC to consider additional capacity and to achieve lower emissions. If selected, these alternatives could range from $90.8 million to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota's investments are subject to the MPUC approval of a cost recovery mechanism.

***Federal Clean Water Act*** — The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the "best technology available" for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit challenging the phase II rulemaking. In January 2007, the court issued its decision and remanded virtually every aspect of the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state's best professional judgment until the EPA is able to fully respond to the court-ordered remand. As a result, the rule's compliance requirements and associated deadlines are currently unknown. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved.

*New York Office of the Attorney General Subpoena* — In September 2007 the Office of the New York Attorney General (NYAG) issued a subpoena pursuant to the Martin Act, a New York statute, to Xcel Energy. The subpoena seeks information and documents related to Xcel Energy's analysis of risks posed by climate change and possible climate legislation and its disclosures of such risks to investors. In a letter accompanying the subpoena, the NYAG asserts that the increase in $CO_2$ emissions upon completion of Comanche 3 (a coal-fired unit), "in combination with Xcel Energy's other coal-fired plants, will subject Xcel to increased financial, regulatory and litigation risks" which need to be disclosed to shareholders. Xcel Energy believes it has fully disclosed these risks, to the extent they can be ascertained, and such disclosures belie the concerns expressed by the NYAG.

*PSCo Notice of Violation* — In July 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche and Pawnee plants in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. It believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

*Cherokee Station Alleged Clean Air Act Violations* — In January 2008, Xcel Energy received a notice letter from Rocky Mountain Clean Air Action stating that the group intends to sue Xcel Energy for alleged Clean Air Act violations at Cherokee Station. The group claims that Cherokee Station's opacity emissions have exceeded allowable limits over the past five years and that its opacity monitors exceeded downtime limits. Xcel Energy disputes these claims and believes they are without merit. The Clean Air Act requires notice be given 60 days prior to filing a lawsuit. If the group does in fact file its threatened lawsuit, Xcel Energy will vigorously defend itself against these claims.

## Asset Retirement Obligations

Xcel Energy records future plant removal obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets in accordance with SFAS No. 143 — "Accounting for Asset Retirement Obligations" (SFAS No. 143). This liability will be increased over time by applying the interest method of accretion to the liability and the capitalized costs will be depreciated over the useful life of the related long-lived assets. The recording of the obligation for regulated operations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

*Recorded ARO* — AROs have been recorded for plant related to nuclear production, steam production, electric transmission and distribution, natural gas transmission and distribution and office buildings. The steam production obligation includes asbestos, ash-containment facilities and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. Generally, this asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination date on the ARO recognition for ash-containment facilities at steam plants was the in-service date of various facilities.

Xcel Energy recognized an ARO for the retirement costs of natural gas mains at NSP-Minnesota, NSP- Wisconsin and PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. The electric transmission and distribution ARO consists of many small potential obligations associated with polychlorinated biphenyls (PCBs), mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the ARO associated with the decommissioning of two NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originates with the in-service date of the facility. Monticello began operation in 1971. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively. See Note 16 to the consolidated financial statements for further discussion of nuclear obligations.

A reconciliation of the beginning and ending aggregate carrying amounts of Xcel Energy's AROs is shown in the table below for the 12 months ended Dec. 31, 2007 and Dec. 31, 2006, respectively:

| | Beginning Balance Jan. 1, 2007 | Liabilities Recognized | Liabilities Settled | Accretion | Revisions to Prior Estimates | Ending Balance Dec. 31, 2007 |
|---|---|---|---|---|---|---|
| | | | (Thousands of Dollars) | | | |
| **Electric Utility Plant:** | | | | | | |
| Steam production asbestos | $ 35,515 | $— | $— | $ 2,049 | $ (1,757) | $ 35,807 |
| Steam production ash containment | 21,416 | — | — | 1,212 | (89) | 22,539 |
| Nuclear production decommissioning | 1,256,763 | — | — | 73,914 | (120,931) | 1,209,746 |
| Electric transmission and distribution | 1,994 | — | — | 43 | (1,767) | 270 |
| **Gas Utility Plant:** | | | | | | |
| Gas transmission and distribution | 44,405 | — | — | 1,100 | — | 45,505 |
| **Common Utility and Other Property:** | | | | | | |
| Common general plant asbestos | 1,858 | — | — | 100 | (681) | 1,277 |
| Total liability | $1,361,951 | $— | $— | $78,418 | $(125,225) | $1,315,144 |

| | Beginning Balance Jan. 1, 2006 | Liabilities Recognized | Liabilities Settled | Accretion | Revisions to Prior Estimates | Ending Balance Dec. 31, 2006 |
|---|---|---|---|---|---|---|
| | | | (Thousands of Dollars) | | | |
| **Electric Utility Plant:** | | | | | | |
| Steam production asbestos | $ 34,323 | $— | $ — | $ 1,971 | $ (779) | $ 35,515 |
| Steam production ash containment | 20,934 | — | — | 1,183 | (701) | 21,416 |
| Steam production retirement | 3,152 | — | (3,309) | 157 | — | — |
| Nuclear production decommissioning | 1,184,968 | — | — | 71,795 | — | 1,256,763 |
| Electric transmission and distribution | 2,350 | — | — | 62 | (418) | 1,994 |
| **Gas Utility Plant:** | | | | | | |
| Gas transmission and distribution | 43,245 | 15 | — | 1,074 | 71 | 44,405 |
| **Common Utility and Other Property:** | | | | | | |
| Common general plant asbestos | 3,034 | — | — | 162 | (1,338) | 1,858 |
| Total liability | $1,292,006 | $15 | $(3,309) | $76,404 | $(3,165) | $1,361,951 |

The fair value of NSP-Minnesota assets legally restricted, for purposes of settling the nuclear ARO is $1.3 billion as of Dec. 31, 2007, including external nuclear decommissioning investment funds and internally funded amounts.

On Sept. 21, 2007, the MPUC approved NSP-Minnesota's remaining lives depreciation filing lengthening the life of the Monticello nuclear plant by 20 years, effective Jan. 1, 2007, which decreased the related ARO and related regulatory asset by $120.9 million in the third quarter of 2007.

***Indeterminate AROs*** — PSCo has underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined, therefore an ARO has not been recorded.

***Removal Costs*** — Xcel Energy accrues an obligation for plant removal costs for other generation, transmission and distribution facilities of its utility subsidiaries. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, the utility subsidiaries have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates.

Accordingly, the recorded amounts of estimated future removal costs are considered regulatory liabilities under SFAS No. 71. Removal costs by entity are as follows at Dec. 31:

| | 2007 | 2006 |
|---|---|---|
| | (Millions of Dollars) | |
| NSP-Minnesota | $342 | $355 |
| NSP-Wisconsin | 94 | 91 |
| PSCo | 374 | 389 |
| SPS | 96 | 85 |
| Total Xcel Energy | $906 | $920 |

## Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $10.8 billion under the Price-Anderson amendment to the Atomic Energy Act of 1954, as amended. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $10.5 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 $100.6 million per reactor per accident 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 $15 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective Aug. 20, 2003. The next adjustment is due on or before Aug. 20, 2008.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.3 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 $15.0 million for business interruption insurance and $32.1 million for property damage insurance if losses exceed accumulated reserve funds.

## Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy's financial position and results of operations.

## Gas Trading Litigation

e prime was a subsidiary of Xcel Energy Markets Holdings Inc., which is a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Twelve lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin in one instance), alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP- Wisconsin deny these allegations and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the United States District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned *Texas-Ohio Energy vs. CenterPoint Energy.* The other eleven cases arising out of the same or similar set of facts are captioned *Fairhaven Power Company vs. EnCana Corporation et al; Ableman Art Glass vs. EnCana Corporation et al; Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. et al; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al; Learjet, Inc. vs. e prime and Xcel Energy Inc et al; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy, Inc. et al; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al and Hartford Regional Medical Center vs. e prime, Xcel Energy et al.* Many of these cases involve multiple defendants and have been or are in the process of being transferred to Judge Phillip Pro of the United States District Court in Nevada, who is the judge assigned to the western area wholesale natural gas antitrust litigation. An exception is *the Missouri Public Service Commission* case, which was remanded to Missouri state court in November 2007.

In April 2005, Judge Pro granted defendants' motion to dismiss based upon the filed rate doctrine in *Texas Ohio Energy*. Based upon this same legal doctrine, Judge Pro subsequently granted defendants' motion to dismiss in *Fairhaven Power Company, Ableman Art Glass and Utility Savings and Refund Services*. Plaintiffs subsequently appealed these dismissals to the Ninth Circuit Court of Appeals. In September 2007, the Ninth Circuit Court of Appeals reversed the dismissal and remanded the lawsuits to Judge Pro for consideration of whether any of plaintiffs' claims are based upon retail rates not directly barred by the filed rate doctrine.

All of the gas trading lawsuits are in the early procedural stages of litigation. No trial dates have been set for any of these lawsuits, however, defendants' motions to dismiss are pending in the *Missouri Public Service Commission* matter, and defendants' summary judgment motions are pending in the *Arandell, Breckenridge, Learjet, and J.P. Morgan* matters.

## Environmental Litigation

***Comanche 3 Permit Litigation*** — In August 2005, Citizens for Clean Air and Water in Pueblo and Southern Colorado and Clean Energy Action filed a complaint in Colorado state court against the CAPCD alleging that the division improperly granted permits to PSCo under Colorado's Prevention of Significant Deterioration program for the construction and operation of Comanche 3. PSCo intervened in the case. In June 2006, the court ruled in PSCo's favor and held that the Comanche 3 permits had been properly granted and plaintiffs' claims to the contrary were without merit. Plaintiffs appealed the decision. In February 2008 the Colorado Court of Appeals affirmed the state court's decision.

***Carbon Dioxide Emissions Lawsuit*** — In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in $CO_2$ emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that $CO_2$ emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its $CO_2$ emissions. In October 2004, Xcel Energy and the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the court granted the motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the Second Circuit Court of Appeals. In June 2007 the Second Circuit Court of Appeals issued an order requesting the parties to file a letter brief regarding the impact of the United States Supreme Court's decision in Massachusetts v. EPA, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in Massachusetts v. EPA, the United States Supreme Court held that $CO_2$ emissions are a "pollutant" subject to regulation by the EPA under the Clean Air Act. In response to the request of the Second Circuit Court of Appeals, in June 2007, the defendant utilities filed a letter brief stating the position that the United States Supreme Court's decision supports the arguments raised by the utilities on appeal. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

***Comer vs. Xcel Energy Inc. et al.*** — In April 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants' $CO_2$ emissions "were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina." Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. In September 2007, plaintiffs filed a notice of appeal to the Fifth Circuit Court of Appeals. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

## Employment, Tort and Commercial Litigation

***Bender et al. vs. Xcel Energy*** — In July 2004, five former NRG officers filed a lawsuit against Xcel Energy in the U.S. District Court for in Minnesota. The lawsuit alleges, among other things, that Xcel Energy violated the Employee Retirement Income Security Act (ERISA) by refusing to make certain deferred compensation payments to the plaintiffs. The complaint also alleges interference with ERISA benefits, breach of contract related to the nonpayment of certain stock options and unjust enrichment. The complaint alleges damages of approximately $6 million.

In May 2006, the court granted Xcel Energy's motion for summary judgment in full and denied the plaintiffs' motion for summary judgment in full. On Oct. 29, 2007, the Eighth Circuit Court of Appeals affirmed the district court's dismissal of plaintiff's lawsuit.

***Siewert vs. Xcel Energy*** — In June 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota's distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. After its motion to dismiss plaintiffs' claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007 the court granted NSP- Minnesota's motion for certification, and the parties have filed briefs on appeal.

***Saemrow Dairy Partnership vs. Xcel Energy*** — In December 2006, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems and in the construction and maintenance of distribution systems. They also alleged failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota's distribution system. Plaintiffs claim losses approximately $9 million. NSP-Minnesota denies all allegations. Mediation has been set for March 2008; and in the event the matter is not resolved, trial is set for October 2008.

***Qwest vs. Xcel Energy Inc.*** — In June 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Denver state court. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. Pursuant to this agreement, Qwest asserted PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. In May 2006, PSCo filed a counterclaim against Qwest asserting Qwest had a duty to PSCo and an obligation under the contract to maintain its poles in a safe and serviceable condition. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. In January 2008, Qwest filed a notice of appeal.

***Hoffman vs. Northern States Power Company*** — In March 2006, a purported class action complaint was filed in Minnesota state court, on behalf of NSP-Minnesota's residential customers in Minnesota, North Dakota and South Dakota for alleged breach of a contractual obligation to maintain and inspect the points of connection between NSP-Minnesota's wires and customers' homes within the meter box. Plaintiffs claim NSP-Minnesota's alleged breach results in an increased risk of fire and is in violation of tariffs on file with the MPUC. Plaintiffs seek injunctive relief and damages in an amount equal to the value of inspections plaintiffs claim NSP-Minnesota was required to perform over the past six years. In August 2006, NSP-Minnesota filed a motion for dismissal on the pleadings. In November 2006, the court issued an order denying NSP-Minnesota's motion, but later, pursuant to a motion by NSP-Minnesota, certified the issues raised in NSP-Minnesota's original motion for appeal as important and doubtful, and NSP-Minnesota filed an appeal with the Minnesota Court of Appeals. On Jan. 22, 2008, the Minnesota Court of Appeals determined the plaintiffs' claims are barred by the filed rate doctrine and remanded the case to the district court for dismissal.

***MGP Insurance Coverage Litigation*** — In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire, and LaCrosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin's insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state circuit court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions.

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of eleven insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Court of Appeals for Minnesota challenging the dismissal of these carriers. In November 2007, Ranger Insurance Company (Ranger) and TIG Insurance Company (TIG) filed a motion to dismiss NSP-Wisconsin's appeal, asserting that NSP-Wisconsin's failure to serve Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company (Harbor), requires dismissal of NSP-Wisconsin's appeal. In February 2008, the Court of Appeals issued an order deferring a decision on the procedural motion filed by Harbor and TIG and referring the motion to the panel assigned to consider the merits of the appeal. The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will operate as a credit to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy's consolidated financial statements.

***Nuclear Waste Disposal Litigation*** — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. DOE's failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE's motion for reconsideration. In February 2008, the DOE filed an appeal to the U.S. Court of Appeals for the Federal Circuit. Results of the judgment will not be recorded in earnings until the appeal and regulatory treatment and amounts to be shared with rate payers has been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit claims damages for the period Jan. 1, 2005 through June 30, 2007, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. The amount of such damages is expected to exceed $40 million. In January 2008, the court granted the DOE's motion to stay, subject to reevaluation after a decision has been filed in any one of the five pending appeals of nuclear waste storage cases.

***Mallon vs. Xcel Energy Inc.*** — In July 2007 Theodore Mallon and TransFinancial Corporation filed a declaratory judgment action against Xcel Energy in U. S. District Court in Colorado (Mallon Federal Action). In this lawsuit, plaintiffs seek a determination that Xcel Energy is not entitled to assert claims against plaintiffs related to the 1984 and 1985 sale of COLI to PSCo, a predecessor of Xcel Energy. In August 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in Colorado state court against Mallon and TransFinancial Corporation (Mallon State Action). In the Mallon State Action, Xcel Energy, PSCo and PSRI seek damages against Mallon and TransFinancial for, among other things, breach of contract and breach of fiduciary duties associated with the sale of the COLI policies. In August 2007, Xcel Energy also filed a motion to stay or, in the alternative, to dismiss the Mallon Federal Action. In September 2007, a motion to stay the Mallon State Court action was subsequently filed by Mallon and TransFinancial. In November 2007, the U.S. District Court in Colorado dismissed the complaint in the Mallon Federal Action and Mallon and TransFinancial subsequently withdrew their motion to stay the Mallon State Court Action.

***Fru-Con Construction Corporation vs. Utility Engineering (UE) et al.*** — In March 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con's complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE's motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

***Lamb County Electric Cooperative (LCEC)*** — In 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging SPS was unlawfully providing service to oil field customers in LCEC's certificated area. In May 2003, the PUCT issued an order denying LCEC's petition based on its determination that SPS in 1976 was granted a certificate to serve the disputed customers. LCEC appealed the decision to the District Court in Travis County, Texas. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the District Court's decision to the Court of Appeals for the Third Supreme Judicial District of the state of Texas. This appeal is currently pending.

In 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination of the legality of SPS providing electric service to the disputed customers. The PUCT order from May 2003, which found SPS was legally serving the disputed customers, collaterally determines the issue of liability contrary to LCEC's position in the suit. An adverse ruling on the appeal of May 2003 PUCT order could result in a different determination of the legality of SPS' service to the disputed customers.

## Other Contingencies

See Note 14 to the consolidated financial statements.

## 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 the DOE fuel disposal assessments of approximately $13 million in 2007, $13 million in 2006 and $12 million in 2005. In total, NSP-Minnesota had paid approximately $373 million to the DOE through Dec. 31, 2007. However, it is not determinable 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 of 1982 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, which consist of storage pools at both sites and a dry cask facility at Prairie Island. With the dry cask storage facility licensed by the NRC, approved in 1994 and again in 2003, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least the end of its current license terms in 2013 and 2014. The Monticello nuclear plant has storage capacity in the storage pool to continue operations until 2010. In 2005, NSP-Minnesota filed a certificate of need to allow interim storage of spent fuel at the Monticello nuclear plant to support license renewal and operation for an additional 20 years. In October 2006, the MPUC issued its approval allowing additional interim spent fuel storage. Minnesota Statutes provide that the MPUC decision become effective June 1, 2007, which allowed the legislature the opportunity to review the MPUC action if desired. On Nov. 8, 2006, the NRC renewed the operating license of the Monticello nuclear plant for an additional 20 years. All of the alternatives for spent fuel storage are being investigated 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.

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 was payable in annual installments for 15 years until 2007. NSP-Minnesota amortized each installment to expense on a monthly basis. The final annual assessment was received and paid in 2006. The amortization of this annual assessment was completed in September 2007. NSP-Minnesota has obtained rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments were amortized.

***Regulatory Plant Decommissioning Recovery*** — Decommissioning of NSP-Minnesota's nuclear facilities, as last approved by the MPUC, is planned for the period from cessation of operations through 2050, assuming the prompt dismantlement method. NSP-Minnesota is currently recording the regulatory costs for decommissioning over the MPUC-approved cost-recovery period and including the accruals in a regulatory liability account. The total decommissioning cost obligation is recorded as an ARO in accordance with SFAS No. 143.

Monticello began operation in 1971 with an original license to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are currently licensed to operate until 2013 and 2014, respectively. In 2003, the Minnesota legislature changed a law that had limited expansion of on-site storage. On Sept. 28, 2006, the MPUC approved Xcel Energy's request for a certificate of need to authorize construction and operation of a dry spent fuel storage facility at Monticello to become effective June 1, 2007. On Nov. 8, 2006, the NRC renewed the operating license of the Monticello nuclear plant for an additional 20 years to 2030. In June 2007, NSP-Minnesota filed for depreciation life extension of the Monticello nuclear plant based on previous NRC and MPUC process approvals. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC on Sept. 21, 2007. Construction of the Monticello Independent Spent Fuel Storage facility, as allowed by the certificate of need approved in 2006, commenced on June 4, 2007. Installation of the horizontal storage modules began in October of 2007 with a fuel loading campaign anticipated to begin in the Spring of 2008. Plant assessments and other work for the Prairie Island applications started in 2006. The Prairie Island operating license extension for an additional 20 years of operation is anticipated to be filed by the end of the first quarter of 2008 with the NRC.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC when decommissioning commences. The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in March 2006, using 2005 cost data with the next update due in October 2008. The MPUC approval decreasing 2006 decommissioning funding for Minnesota retail customers resulted from an extension of remaining life for the Monticello unit by 10 years (from 2010 to 2020). Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts, 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. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

Consistent with cost recovery in utility customer rates, NSP-Minnesota records annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Current authorized funding presumes that costs will escalate in the future at a rate of 3.61 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 5.40 percent, net of tax, for external funding. The net unrealized gain on nuclear decommissioning investments is deferred as a regulatory liability based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

In 2006, the Nuclear Decommissioning Trust (NDT) fund also recorded the sale of certain investments in the non-qualified fund and the reinvestment of the proceeds into the qualified fund. The sale and reinvestment, along with the transfer of securities was part of a transaction intended to consolidate trust fund accounts into an income tax advantaged fund, resulting from the Energy Act. The transfer of funds was completed in the fourth quarter of 2006.

At Dec. 31, 2007, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning expense of $1.2 billion. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters. Xcel Energy believes future decommissioning cost expense will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO in accordance with SFAS No. 143.

| | 2007 | 2006 |
|---|---|---|
| | (Thousands of Dollars) | |
| Estimated decommissioning cost obligation from most recently approved study (2005 dollars) | $ 1,683,750 | $ 1,683,750 |
| Effect of escalating costs to 2007 and 2006 dollars (3.61 percent per year) | 123,761 | 60,783 |
| Estimated decommissioning cost obligation in current dollars | 1,807,511 | 1,744,533 |
| Effect of escalating costs to payment date (3.61 percent per year) | 1,319,315 | 1,382,293 |
| Estimated future decommissioning costs (undiscounted) | 3,126,826 | 3,126,826 |
| Effect of discounting obligation (using risk-free interest rate) | (1,502,030) | (1,675,114) |
| Discounted decommissioning cost obligation | 1,624,796 | 1,451,712 |
| Assets held in external decommissioning trust | 1,317,564 | 1,200,688 |
| Discounted decommissioning obligation in excess of assets currently held in external trust | $ 307,232 | $ 251,024 |

Decommissioning expenses recognized include the following components:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| | | (Thousands of Dollars) | |
| Annual decommissioning cost expense reported as depreciation expense: | | | |
| Externally funded | $43,392 | $48,069 | $ 80,582 |
| Internally funded (including interest costs) | (759) | (5,046) | (57,561) |
| Net decommissioning expense recorded | $42,633 | $43,023 | $ 23,021 |

Reductions to expense for internally-funded portions in 2007, 2006 and 2005 are a direct result of the 2005 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the remaining operating life of the unit. The 2005 nuclear decommissioning filing approved in 2006 has been used for the regulatory presentation and all the updated parameters were used for 2005. The change in estimated decommission obligations was calculated using a life extension cost estimate for Monticello.

## 17. Regulatory Assets and Liabilities

Xcel Energy's regulated businesses prepare its consolidated financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the consolidated financial statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow to be collected, or may require to be paid back to customers in future electric and natural gas rates. Any portion of Xcel Energy's business that is not regulated cannot use SFAS No. 71 accounting. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of SFAS No. 71 under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in its consolidated statement of income. The components of unamortized regulatory assets and liabilities of continuing operations shown on the consolidated balance sheets at Dec. 31 are:

| | See Note(s) | Remaining Amortization Period | 2007 | 2006 |
|---|---|---|---|---|
| | | (Thousands of Dollars) | | |
| **Regulatory Assets** | | | | |
| Current regulatory asset — Unrecovered fuel costs | 1 | Less than one year | $ 73,415 | $ 258,600 |
| Pension and employee benefit obligations | 10 | Various | $ 387,127 | $ 475,815 |
| AFDC recorded in plant[(a)] | | Plant lives | 189,698 | 179,023 |
| Conservation programs[(a)] | | Various | 119,839 | 124,123 |
| Contract valuation adjustments[(b)] | 12 | Term of relatedcontract | 106,649 | 109,221 |
| Losses on reacquired debt | 1 | Term of related debt | 73,002 | 74,420 |
| Environmental costs | 15,16 | Generally four to six years once actual expenditures are incurred | 55,038 | 35,715 |
| Renewable resource costs | | One to two years | 51,785 | 49,902 |
| Net asset retirement obligations[(c)] | 1,15 | Plant lives | 39,891 | 54,550 |
| Unrecovered natural gas costs | 1 | One to two years | 22,505 | 17,943 |
| State commission accounting adjustments[(a)] | | Various | 13,828 | 13,950 |
| MISO Day 2 costs | 1 | To be determined in future rate proceedings | 12,035 | 11,014 |
| Nuclear fuel storage | | Four years | 11,578 | 14,473 |
| Nuclear decommissioning costs | | To be determined in future rate proceedings | 11,149 | 9,325 |
| Rate case costs | 1 | Various | 9,630 | 8,689 |
| Other | | Various | 11,689 | 10,982 |
| Total noncurrent regulatory assets | | | $1,115,443 | $1,189,145 |
| **Regulatory Liabilities** | | | | |
| Current regulatory liability — Overrecovered fuel costs[(d)] | | | $ 34,451 | $ 4,279 |
| Plant removal costs | 1,15 | | $ 906,996 | $ 920,583 |
| Pension and employee benefit obligations | 10 | | 205,133 | 196,803 |
| Contract valuation adjustments[(b)] | 12 | | 108,533 | 56,745 |
| Investment tax credit deferrals | | | 72,686 | 78,205 |
| Deferred income tax adjustments | 1 | | 59,282 | 67,002 |
| Gain on sale of emission allowances | 1 | | 21,334 | 7,417 |
| Interest on income tax refunds | | | 3,472 | 5,233 |
| Over recovered fuel costs | | | 149 | 10,054 |
| Other | | | 12,402 | 22,615 |
| Total noncurrent regulatory liabilities | | | $1,389,987 | $1,364,657 |

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(b) Includes the fair value of certain long-term purchased power agreements used to meet energy capacity requirements.
(c) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(d) Included in other current liabilities of $419,209 and $347,809 at Dec. 31, 2007 and 2006, respectively, in the consolidated balance sheets.

## 18. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin, and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Given the similarity of the regulated electric utility operations of its utility subsidiaries, and the similarity of the regulated natural gas utility operations its utility subsidiaries, Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.

  In October 2005, SPS reached a definitive agreement to sell its delivery system operations in Oklahoma, Kansas and a small portion of Texas to Tri-County Electric Cooperative. Effective July 31, 2006, SPS completed the sale to Tri-County Electric Cooperative for $24.5 million and a gain of $6.1 million was recognized. SPS now provides wholesale service to Tri-County Electric Cooperative.

- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.

Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

To report income from continuing operations for regulated electric and regulated 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 consolidated financial statements.

| | Regulated Electric Utility | Regulated Natural Gas Utility | All Other | Reconciling Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| | (Thousands of Dollars) | | | | |
| **2007** | | | | | |
| Operating revenues from external customers | $ 7,847,992 | $ 2,111,732 | $ 74,446 | $ — | $ 10,034,170 |
| Intersegment revenues | 1,000 | 16,680 | — | (17,680) | — |
| Total revenues | $ 7,848,992 | $ 2,128,412 | $ 74,446 | $ (17,680) | $ 10,034,170 |
| Depreciation and amortization | $ 714,411 | $ 98,925 | $ 13,837 | $ — | $ 827,173 |
| Financing costs, mainly interest expense | 318,937 | 43,985 | 180,757 | (14,834) | 528,845 |
| Income tax expense (benefit) | 343,184 | 50,150 | (98,850) | — | 294,484 |
| Income (loss) from continuing operations | $ 554,670 | $ 108,054 | $ (22,583) | $ (64,242) | $ 575,899 |
| **2006** | | | | | |
| Operating revenues from external customers | $ 7,608,018 | $ 2,155,999 | $ 76,287 | $ — | $ 9,840,304 |
| Intersegment revenues | 820 | 12,296 | — | (13,116) | — |
| Total revenues | $ 7,608,838 | $ 2,168,295 | $ 76,287 | $ (13,116) | $ 9,840,304 |
| Depreciation and amortization | $ 711,930 | $ 94,356 | $ 15,612 | $ — | $ 821,898 |
| Financing costs, mainly interest expense | 302,114 | 44,965 | 133,558 | (24,605) | 456,032 |
| Income tax expense (benefit) | 283,552 | 37,656 | (139,797) | — | 181,411 |
| Income (loss) from continuing operations | $ 503,119 | $ 70,609 | $ 51,570 | $ (56,617) | $ 568,681 |
| **2005** | | | | | |
| Operating revenues from external customers | $ 7,243,637 | $ 2,307,385 | $ 74,455 | $ — | $ 9,625,477 |
| Intersegment revenues | 767 | 17,732 | — | (18,499) | — |
| Total revenues | $ 7,244,404 | $ 2,325,117 | $ 74,455 | $ (18,499) | $ 9,625,477 |
| Depreciation and amortization | $ 662,236 | $ 89,174 | $ 15,911 | $ — | $ 767,321 |
| Financing costs, mainly interest expense | 301,185 | 47,145 | 108,538 | (14,242) | 442,626 |
| Income tax expense (benefit) | 258,161 | 32,923 | (117,545) | — | 173,539 |
| Income (loss) from continuing operations | $ 440,578 | $ 71,213 | $ 35,733 | $ (48,486) | $ 499,038 |

## 19. Summarized Quarterly Financial Data (Unaudited)

Summarized quarterly unaudited financial data is as follows:

| | Quarter Ended | | | |
|---|---|---|---|---|
| | March 31, 2007 | June 30, 2007 | Sept. 30, 2007 | Dec. 31, 2007 |
| | (Thousands of Dollars, except per share amounts) | | | |
| Revenue | $2,763,662 | $2,267,292 | $2,399,997 | $2,603,219 |
| Operating income | 278,128 | 289,157 | 494,845 | 288,941 |
| Income from continuing operations | 118,514 | 67,695 | 254,720 | 134,969 |
| Discontinued operations — income | 1,197 | 1,082 | 97 | (927) |
| Net income | 119,711 | 68,777 | 254,817 | 134,042 |
| Earnings available for common shareholders | 118,651 | 67,717 | 253,757 | 132,982 |
| Earnings per share total — basic | $ 0.29 | $ 0.16 | $ 0.60 | $ 0.31 |
| Earnings per share total — diluted | 0.28 | 0.16 | 0.59 | 0.31 |

| | Quarter Ended | | | |
|---|---|---|---|---|
| | March 31, 2006 | June 30, 2006 | Sept. 30, 2006 | Dec. 31, 2006 |
| | (Thousands of Dollars, except per share amounts) | | | |
| Revenue | $ 2,888,104 | $ 2,073,873 | $ 2,411,591 | $ 2,466,736 |
| Operating income | 312,749 | 224,658 | 410,103 | 229,482 |
| Income from continuing operations | 149,812 | 97,936 | 224,175 | 96,758 |
| Discontinued operations — income | 1,486 | 339 | 287 | 960 |
| Net income | 151,298 | 98,275 | 224,462 | 97,718 |
| Earnings available for common shareholders | 150,238 | 97,215 | 223,402 | 96,658 |
| Earnings per share total — basic | $ 0.37 | $ 0.24 | $ 0.55 | $ 0.24 |
| Earnings per share total — diluted | 0.36 | 0.24 | 0.53 | 0.23 |

## Item 9 — Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

During 2006 and 2007, and through the date of this report, there were no disagreements with the independent public accountants on accounting principles or practices, financial statement disclosures, or auditing scope or procedures.

## Item 9A — Controls and Procedures

### Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2007, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and the CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures are effective.

### Internal Controls Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, in general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2007 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board (PCAOB) and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

## Item 9B — Other Information

None.

# PART III

## Item 10 — Directors, Executive Officers, and Corporate Governance

Information required under this Item with respect to directors is set forth in Xcel Energy's Proxy Statement for its 2008 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

## Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy's Proxy Statement for its 2008 Annual Meeting of Shareholders, which is incorporated by reference.

## Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information concerning the security ownership of the directors and officers of Xcel Energy and securities authorized for issuance under equity compensation plans is contained in Xcel Energy's Proxy Statement for its 2008 Annual Meeting of Shareholders which is incorporated by reference.

## Item 13 — Certain Relationships, Related Transactions, and Director Independence

Information concerning relationships and related transactions of the directors and officers of Xcel Energy is contained in Xcel Energy's Proxy Statement for its 2008 Annual Meeting of Shareholders, which is incorporated by reference.

## Item 14 — Principal Accounting Fees and Services

Information concerning fees paid to the principal accountant for each of the last two years is contained in Xcel Energy's Proxy Statement for its 2008 Annual Meeting of Shareholders, which is incorporated by reference.

# Part IV

## Item 15 — Exhibits, Financial Statement Schedules

1. Consolidated Financial Statements:
   Management Report on Internal Controls — For the year ended Dec. 31, 2007.
   Reports of Independent Registered Public Accounting Firm — For the years ended Dec. 31, 2007, 2006 and 2005.
   Consolidated Statements of Income — For the three years ended Dec. 31, 2007, 2006 and 2005.
   Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2007, 2006 and 2005.
   Consolidated Balance Sheets — As of Dec. 31, 2007 and 2006.
2. Schedule I — Condensed Financial Information of Registrant.
   Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2007, 2006 and 2005.
3. Exhibits

---

* Indicates incorporation by reference

\+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

### Xcel Energy

2.01* Order confirming NRG plan of reorganization dated Nov. 24, 2003 (Exhibit 99.b.10 to Form POS AMC (file no. 070-10152) dated Dec. 1, 2003).
2.02* Release-Based Amount Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.03 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.03* Settlement Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.04 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.04* Employee Matters Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.05 to Form 10-K (file no. 001-03034) dated March 15, 2004).
2.05* Tax Matters Agreement dated Dec. 5, 2003 between Xcel Energy Inc. and NRG Energy, Inc. (Exhibit 2.06 to Form 10-K (file no. 001-03034) dated March 15, 2004).

### Xcel Energy

3.01* Restated Articles of Incorporation of Xcel Energy (Exhibit 4.01 to Form 8-K (file no. 001-03034) filed Aug. 21, 2000).
3.02* By-Laws of Xcel Energy (Exhibit 3.01 to Form 10-Q (file no. 001-03034) filed Aug. 4, 2004).

### Xcel Energy

4.01* Trust Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.02* Supplemental Trust Indenture dated Dec. 15, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee, creating $600 million principal amount of 7 percent Senior Notes, Series due 2010. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.03* Stockholder Protection Rights Agreement dated Dec. 13, 2000, between Xcel Energy Inc. and Wells Fargo Bank Rights Agent. (Exhibit 1 to Form 8-K (file no. 001-03034) dated Minnesota, N.A., as Jan. 4, 2001).
4.04* Redemption Agreement dated Nov. 25, 2002 by and among Xcel Energy Inc. and the Buyers listed on Exhibit A thereto. (Exhibit 4.136 to Form 10-K (file no. 001-03034) dated March 31, 2003).
4.05* Indenture dated Nov. 21, 2002 between Xcel Energy Inc. and Wells Fargo Bank NA, 7.5 percent convertible senior notes due 2007 (Exhibit 4.137 to Form 10-K (file no. 001-03034) dated March 31, 2003).
4.06* Supplemental Trust Indenture No. 2 dated June 15, 2003 between Xcel Energy Inc. and Wells Fargo Bank NA, supplementing trust indenture dated Dec. 1, 2000 (Exhibit 4.01 to Form 10-Q (file no. 001-03034) dated Aug. 15, 2003).
4.07* Indenture dated Nov. 15, 2003 between Xcel Energy Inc. and Wells Fargo Bank Minnesota NA, 7.5 percent convertible senior notes due 2008. (Exhibit 4.10 to Form 10-K (file no. 001-03034), dated March 15, 2004).
4.08* Registration Rights Agreement dated Nov. 21, 2003 among Xcel Energy Inc., Citadel Equity Fund Ltd., Citadel Credit Trading Ltd., and Citadel Jackson Investment Fund Ltd. (Exhibit 4.10 to Form 10-K (file no. 001-03034), dated March 15, 2004).
4.09* Form of Stock Option Agreement Dated Aug. 5, 2005 (Exhibit 4.04 to Form S-8 (file no. 001-03034) dated Aug. 5, 2005).
4.10* Form of Restricted Stock Agreement Dated Aug. 5, 2005 (Exhibit 4.08 to Form S-8 (file no. 001-03034) dated Aug. 5, 2005).
4.11 Supplemental Trust Indenture dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, National Association as Trustee, creating $300,000,000 principal amount of 6.5 percent Senior Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
4.12 $800,000,000 Credit Agreement dated Dec. 14, 2006 between Xcel Energy Inc. and various lenders (Exhibit 99.01 to Form 8-K (file no. 001-03034) dated Dec. 14, 2006).
4.13* Registration Rights Agreement dated March 30, 2007 between Xcel Energy Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Greenwich Capital Markets, Inc. and Lazard Capital Markets LLC. (Exhibit 10.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).
4.14* Supplemental Indenture dated March 30, 2007 between Xcel Energy Inc. and Wells Fargo Bank, National Association, as Trustee, creating $253,979,000 aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).

## NSP-Minnesota

4.15* Supplemental and Restated Trust Indenture, dated May 1, 1988, from Northern States Power Co. (a Minnesota corporation) to Harris Trust and Savings Bank, as Trustee. (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year 1988, file no. 001-03034). Supplemental Indentures between NSP-Minnesota and said Trustee, supplemental to Exhibit 4.14, dated as follows:

4.16* July 1, 1989 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated July 7, 1989).

4.17* June 1, 1990 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 1, 1990).

4.18* Oct. 1, 1992 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 13, 1992).

4.19* April 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 1993).

4.20* Dec. 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 7, 1993).

4.21* Feb. 1, 1994 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Feb. 10, 1994).

4.22* Oct. 1, 1994 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 5, 1994).

4.23* June 1, 1995 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).

4.24* April 1, 1997 (Exhibit 4.47 to Form 10-K (file no. 001-03034) for the year 1997).

4.25* March 1, 1998 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).

4.26* May 1, 1999 (Exhibit 4.49 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.27* June 1, 2000 (Exhibit 4.50 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.28* Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.29* June 1, 2002 (Exhibit 4.05 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).

4.30* June 1, 2002 (Exhibit 4.06 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).

4.31* Aug. 1, 2002 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 22, 2002).

4.32* Aug. 1, 2003 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 6, 2003).

4.33* May 1, 2003 (Exhibit 4.73 to Form 10-K (file no. 000-03034) for the year ended Dec. 31, 2003).

4.34* July 1, 2005 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K (file no. 001-31387) dated July 14, 2005).

4.35* Trust Indenture, dated July 1, 1999, between Northern States Power Co. (a Minnesota corporation) and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).

4.36* Supplemental Trust Indenture, dated July 15, 1999, between Northern States Power Co. (a Minnesota corporation) and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).

4.37* Supplemental Trust Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, Northern States Power Co. (a Minnesota corporation) and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).

4.38* Supplemental Trust Indenture dated June 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.05 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).

4.39* Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.06 to Form 10-Q (file no. 000-31709) dated Sept. 30, 2002).

4.40* Supplemental Trust Indenture dated July 1, 2002, supplemental to the Indenture dated July 1, 1999, between Northern States Power Co. (a Minnesota Corporation) and Wells Fargo Bank Minnesota, National Association, as trustee (Exhibit 4.01 to Form 8-K (file no. 000-31709) dated July 8, 2002).

4.41* Supplemental Trust Indenture dated Aug. 1, 2002, supplemental to the Indentures dated Feb. 1, 1937 and May 1, 1988, between Northern States Power Co. (a Minnesota Corporation) and BNY Midwest Trust Co., as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 22, 2002).

4.42* Supplemental Trust Indenture dated Aug. 1, 2003 between Northern States Power Co. (a Minnesota corporation) and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988 (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated Aug. 6, 2003).

4.43* Supplemental Trust Indenture dated May 1, 2003 between Northern States Power Co. (a Minnesota corporation) and BNY Midwest Trust Co., supplementing indentures dated Feb. 1, 1937 and May 1, 1988.

4.44* Supplemental Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250,000,000 principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP Minnesota Current Report on Form 8-K, dated July 14, 2005).

4.45* Supplemental Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400,000,000 principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, dated May 18, 2006).

4.46* $500,000,000 Credit Agreement dated Dec. 14, 2006 between NSP-Minnesota and various lenders (Exhibit 99.01 to Form 8-K (file no. 000-31387) dated Dec. 14, 2006).

4.47* Supplemental Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).

## NSP-Wisconsin

4.48* Supplemental and Restated Trust Indenture, dated March 1, 1991. (Exhibit 4.01K to Registration Statement 33-39831).

4.49* Supplemental Trust Indenture, dated April 1, 1991. (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).

4.50* Supplemental Trust Indenture, dated March 1, 1993. (Exhibit to Form 8-K (file no. 001-03140) dated March 3, 1993).

4.51* Supplemental Trust Indenture, dated Oct. 1, 1993. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 21, 1993).

4.52* Supplemental Trust Indenture, dated Dec. 1, 1996. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).

4.53* Trust Indenture dated Sept. 1, 2000, between Northern States Power Co. (a Wisconsin corporation) and Firstar Bank, N.A. as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).

4.54* Supplemental Trust Indenture dated Sept. 15, 2000, between Northern States Power Co. (a Wisconsin corporation) and Firstar Bank, N.A. as Trustee, creating $80 million principal amount of 7.64 percent Senior Notes, Series due 2008. (Exhibit 4.02 to Form 8-K (file no 001-03140) dated Sept. 25, 2000).

4.55* Supplemental Trust Indenture dated Sept. 1, 2003 between Northern States Power Co. (a Wisconsin corporation) and US Bank NA, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).

## PSCo

4.56* Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).

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

| Dated as of | Previous Filing: Form; Date or file no. | Exhibit No. | Dated as of | Previous Filing: Form; Date or file no. | Exhibit No. |
|---|---|---|---|---|---|
| Nov. 1, 1993 | S-3, (33-51167) | 4(b)(2) | Aug. 15, 2002 | 10-Q, Sept. 30, 2002 | 4.03 |
| Jan. 1, 1994 | 10-K, 1993 | 4(b)(3) | Sept. 1, 2002 | 8-K, Sept. 18, 2002 | 4.01 |
| Sept. 2, 1994 | 8-K, September 1994 | 4(b) | Sept. 15, 2002 | 10-Q, Sept. 30, 2002 | 4.04 |
| May 1, 1996 | 10-Q, June 30, 1996 | 4(b) | March 1, 2003 | S-3, April 14, 2003 (333-104504) | 4(b)(3) |
| Nov. 1, 1996 | 10-K, 1996 | 4(b)(3) | April 1, 2003 | 10-Q May 15, 2003 (001-03034) | 4.02 |
| Feb. 1, 1997 | 10-Q, March 31, 1997 | 4(b) | May 1, 2003 | S-4, June 11, 2003 (333-106011) | 4.9 |
| April 1, 1998 | 10-Q, March 31,1998 | 4(b) | Sept. 1, 2003 | 8-K, Sept. 2, 2003 (001-03280) | 4.02 |
| | | | Sept. 15, 2003 | Xcel 10-K, March 15, 2004 (001-03034) | 4.100 |
| | | | Aug. 1, 2005 | PSCo 8-K, Aug. 18, 2005 (001-03280) | 4.02 |
| | | | Aug. 1, 2007 | PSCo 8-K, Aug. 14, 2007 (001-03280) | 4.01 |

4.62* Indenture dated July 1, 1999, between Public Service Co. of Colorado and The Bank of New York, providing for the issuance of Senior Debt Securities and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).

4.63* Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129,500,000 Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A. (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file number 001-3280).

4.64* $700,000,000 Credit Agreement dated Dec. 14, 2006 between PSCo and various lenders (Exhibit 99.01 to Form 8-K (file no. 001-03280) dated Dec. 14, 2006).

4.65* Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust National Association, as successor Trustee. (Exhibit 4.01 to PSCo Form 8-K (file no 001-3280) dated Aug. 14, 2007).

## SPS

4.66* Indenture dated Feb. 1, 1999 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).

4.67* First Supplemental Indenture dated March 1, 1999 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 99.3 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).

4.68* Second Supplemental Indenture dated Oct. 1, 2001 between Southwestern Public Service Co. and The Chase Manhattan Bank (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 23, 2001).

4.69* Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between Southwestern Public Service Co. and JPMorgan Chase Bank, as successor trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).

4.70* Fourth Supplemental Indenture dated Oct. 1, 2006 between Southwestern Public Service Co. and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).

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

4.72* $250,000,000 Credit Agreement dated Dec. 14, 2006 between SPS and various lenders (Exhibit 99.01 to Form 8-K (file no. 001-03789) dated Dec. 14, 2006).

## Xcel Energy

10.01*+ Xcel Energy Omnibus Incentive Plan (Exhibit A to Form DEF-14A (file no. 001-03034) filed Aug. 29, 2000).

10.02*+ Employment Agreement dated March 24, 1999, among Northern States Power Co. (a Minnesota corporation), New Century Energies, Inc. and Wayne H. Brunetti (Exhibit 10(b) to New Century Energies, Inc. Form 10-Q, (file no. 001-12927) dated March 31, 1999).

10.03*+ Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to NSP-Minnesota Form 10-Q (file no. 001-03034) for the quarter ended March 31, 1998).

10.04*+ New Century Energies Omnibus Incentive Plan, (Exhibit A to New Century Energies, Inc. Form DEF 14A (file no. 001-12927) filed March 26, 1998.

10.05*+ Supplemental Executive Retirement Plan (Exhibit 10(e) (1) to New Century Energies, Inc. Form 10-K (file no. 001-12927) dated Dec. 31, 1998).

10.06*+ Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (Exhibit 10(e)(2) to PSCo Form 10-K (file no. 001-3280) dated Dec. 31, 1991).

10.07*+ Supplemental Retirement Income Plan as amended July 23, 1991 (Exhibit 10(d) to SPS Form 10-K, (file no. 001-03789) dated Aug. 31, 1996).
10.08*+ Xcel Energy Senior Executive Severance and Change-in-Control Policy dated Oct. 22, 2003 (Exhibit 10.10 to SPS Form S-4, (file no. 333-112032) dated Jan. 21, 2004).
10.09*+ Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated Jan. 1, 2004 (Exhibit B to Form DEF-14A (file no. 001-03034) dated Apr. 9, 2004).
10.10*+ Xcel Energy Nonqualified Deferred Compensation Plan (2002 restatement) (Exhibit 10.23 to Xcel Energy Form 10-K (file no. 001-03034) dated March 15, 2004).
10.11*+ Xcel Energy Non-employee Directors' Deferred Compensation Plan (Exhibit 10.24 to Xcel Energy Form 10-K (file no. 001-03034) dated March 15, 2004).
10.12* Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.13* Securities Litigation Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.14* ERISA Actions Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.02 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.15* Shareholder Derivative Action Settlement Agreement as of Dec. 31, 2004 and approved Jan. 14, 2005 (Exhibit 10.03 to Form 8-K (file no. 001-03034) dated Jan. 14, 2005).
10.16*+ Employment Agreement, effective Dec. 15, 1997, between company and Mr. Paul J. Bonavia, as amended (Exhibit 10.25 to Xcel Energy Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2004).
10.17*+ Xcel Energy Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.06 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.18*+ Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.19*+ Xcel Energy Omnibus Incentive Plan Form of Performance Share Agreement (Exhibit 10.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.20*+ Xcel Energy Omnibus Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.07 to Xcel Energy Form 10-Q (file no. 001-03034) dated June 30, 2005).
10.21*+ Xcel Energy Omnibus 2005 Incentive Plan (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated May 25, 2005).
10.22*+ Xcel Energy Executive Annual Incentive Award Plan (Exhibit 10.02 to Form 8-K (file no. 001-03034) dated May 25, 2005).
10.23*+ Xcel Energy Amended Employment Agreement, dated as of June 29, 2005, by and between Xcel Energy Inc., a Minnesota corporation, and Wayne H. Brunetti (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated June 29, 2005).
10.24*+ Xcel Energy Supplemental Executive Retirement Plan (Exhibit 10.01 to Form 8-K (file no. 001-03034) dated Dec. 13, 2005).
10.25*+ First Amendment to the Xcel Energy Senior Executive Severance and Change-In-Control Policy dated Oct. 25, 2006.
10.26*+ Agreement, dated March 20, 2007 between Mr. Gary R. Johnson and Xcel Energy Inc. (Exhibit 10.1 to Form 8-K (file no. 001-03034) dated March 20, 2007).
10.27* Letter dated Sept. 19, 2007, from Xcel Energy Inc. to the U.S. Department of Justice (DOJ) submitting its offer to settle the COLI tax dispute and Letter dated Sept. 21, 2007 from the DOJ to Xcel Energy Inc. accepting the settlement offer. (Exhibit 10.1 to Form 10-Q (file no. 001-03034) for the quarter ended Sept. 30, 2007).
10.28*+ Second Amendment to the Xcel Energy Senior Executive Severance and Change-in-Control Policy. (Exhibit 10.01 to Xcel Energy's Form 8-K (file no. 001-03034) dated May 23, 2007).
10.29*+ Amendment Four to Employment Agreement between Xcel Energy Inc. and Paul Bonavia (Exhibit 10.02 to Xcel Energy's Form 8-K (file no. 001-03034) dated May 23, 2007).
10.30+ Xcel Energy executive officer salaries, annual bonus targets and long-term compensation awards for 2008.
10.31+ Compensation and reimbursement practices for Xcel Energy non-employee directors.

## NSP-Minnesota

10.32* Facilities Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (KV) line. (Exhibit 5.06I to file no. 2-54310).
10.33* Transactions Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 KV line. (Exhibit 5.06J to file no. 2-54310).
10.34* Coordinating Agreement, dated July 21, 1976, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 KV line. (Exhibit 5.06K to file no. 2-54310).
10.35* Ownership and Operating Agreement, dated March 11, 1982, between Northern States Power Co. (a Minnesota corporation), Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.36* Power Agreement, dated June 14, 1984, between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.37* Power Agreement, dated August 1988, between Northern States Power Co. (a Minnesota corporation) and Minnkota Power Co. (Exhibit 10.08 to Form 10-K for the year 1988, file no. 001-03034).
10.38* Amended agreement for the sale of thermal energy dated Jan. 1, 1983 between NRG Energy (formerly known as Norenco Corp.) and Northern States Power Co. (a Minnesota corporation) and Norenco Corp. (Exhibit 10.33 to NRG's Registration on Form S-1, file no. 333-35096).
10.39* Operations and maintenance agreement dated Nov. 1, 1996 between NRG Energy and Northern States Power Co. (a Minnesota corporation). (Exhibit 10.34 to NRG's Registration on Form S-1, file no. 333-35096).
10.40* Amended Agreement for the sale of thermal energy and wood byproduct dated Dec. 1, 1986 between Northern States Power Co. (a Minnesota corporation) and Norenco Corp. (Exhibit 10.36 to NRG's Registration on Form S-1, file no. 333-35096).

10.41* Restated Interchange Agreement dated Jan. 16, 2001 between Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).

10.42* 500 megawatt System Participation Power Sale Agreement dated July 30, 2002 between Northern States Power Co. (a Minnesota corporation) and the Manitoba Hydro-Electric Board (Exhibit 99.01 to NSP-Minnesota Form 8-K (file no.001-31387) dated March 25, 2003).

## NSP-Wisconsin

10.43* Restated Interchange Agreement dated Jan. 16, 2001 between Northern States Power Co. (a Wisconsin corporation) and Northern States Power Co. (a Minnesota corporation) (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).

## PSCo

10.44* Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between Public Service Co. of Colorado and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10(c)(1)).

10.45* First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between Public Service Co. of Colorado and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10(c)(2)).

10.46* Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).

10.47* Settlement Agreement among Public Service Co. of Colorado and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).

## SPS

10.48* Coal Supply Agreement (Harrington Station) between Southwestern Public Service Co. and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).

10.49* Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K, (file no. 001-03789) May 14, 1979 — Exhibit 5(A)).

10.50* Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K, (file no. 3789) May 14, 1979 — Exhibit 5(B)).

10.51* Coal Supply Agreement (Tolk Station) between Southwestern Public Service Co. and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(b)).

10.52* Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(c)).

10.53* Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and Southwestern Public Service Co.

## Xcel Energy

12.01 Statement of Computation of Ratio of Earnings to Fixed Charges.

21.01 Subsidiaries of Xcel Energy Inc.

23.01 Consent of Independent Registered Public Accounting Firm.

24.01 Written Consent Resolution of the Board of Directors of Xcel Energy Inc., adopting Power of Attorney

31.01 Principal Executive Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.02 Principal Financial Officer's certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.01 Statement pursuant to Private Securities Litigation Reform Act of 1995.

# SCHEDULE I

## CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.
### Statements of Income

| | Year ended Dec. 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands of Dollars) | | |
| Income: | | | |
| Equity in income of subsidiaries | $640,140 | $625,298 | $547,524 |
| Total income | 640,140 | 625,298 | 547,524 |
| Expenses and other deductions: | | | |
| Operating expenses | 7,630 | 9,143 | 9,151 |
| Other income | (5,556) | (8,980) | (6,047) |
| Interest charges and financing costs | 118,017 | 107,778 | 87,804 |
| Total expenses and other deductions | 120,091 | 107,941 | 90,908 |
| Income from continuing operations before taxes | 520,049 | 517,357 | 456,616 |
| Income tax benefit | (55,850) | (51,324) | (42,422) |
| Income from continuing operations | 575,899 | 568,681 | 499,038 |
| Income from discontinued operations, net of tax | 1,449 | 3,073 | 13,934 |
| Net income | 577,348 | 571,754 | 512,972 |
| Preferred dividend requirements | 4,241 | 4,241 | 4,241 |
| Earnings available to common stockholders | $573,107 | $567,513 | $508,731 |

# CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.
## Statements of Cash Flows

*(thousands of dollars)*

| | Years Ended Dec. 31 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Operating activities:** | | | |
| **Net cash provided by operating activities** | $ 566,688 | $ 634,128 | $ 391,776 |
| **Investing activities:** | | | |
| Return of capital from subsidiaries | 129,551 | 201,185 | 262,378 |
| Capital contributions to subsidiaries | (559,266) | (576,600) | (504,402) |
| **Net cash used in investing activities** | (429,715) | (375,415) | (242,024) |
| **Financing activities:** | | | |
| Proceeds from (repayment of) short-term borrowings — net | 238,877 | (211,716) | 325,516 |
| Proceeds from issuance of long-term debt | — | 294,830 | 484,824 |
| Repayment of long-term debt | — | — | (625,000) |
| Proceeds from issuance of common stock | 10,539 | 16,275 | 9,085 |
| Early participation payment on debt exchange | (4,859) | — | — |
| Dividends paid | (378,892) | (358,746) | (343,092) |
| **Net cash used in financing activities** | (134,335) | (259,357) | (148,667) |
| Net increase (decrease) in cash and cash equivalents | 2,638 | (644) | 1,085 |
| Cash and cash equivalents at beginning of year | 523 | 1,167 | 82 |
| Cash and cash equivalents at end of year | $ 3,161 | $ 523 | $ 1,167 |

# CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

## Balance Sheets

*(thousands of dollars)*

| | 2007 | 2006 |
|---|---|---|
| **Assets** | | |
| Cash and cash equivalents | $ 3,161 | $ 523 |
| Accounts receivable from subsidiaries | 187,522 | 171,434 |
| Other current assets | 29,313 | 26,443 |
| Total current assets | 219,996 | 198,400 |
| Investment in subsidiaries | 7,790,574 | 7,261,515 |
| Other assets | 16,926 | 39,998 |
| Noncurrent assets related to discontinued operations | 40,460 | 40,152 |
| Total other assets | 7,847,960 | 7,341,665 |
| **Total assets** | **$8,067,956** | **$7,540,065** |
| **Liabilities and Equity** | | |
| Dividends payable | $ 99,681 | $ 91,685 |
| Short- term debt | 602,962 | 343,800 |
| Other current liabilities | 49,396 | 29,257 |
| Current liabilities related to discontinued operations | 535 | 358 |
| Total current liabilities | 752,574 | 465,100 |
| Other liabilities | 11,786 | 23,476 |
| Long-term debt | 897,614 | 1,129,687 |
| Preferred stockholders' equity | 104,980 | 104,980 |
| Common stockholders' equity | 6,301,002 | 5,816,822 |
| Total capitalization | 7,303,596 | 7,051,489 |
| **Total liabilities and equity** | **$8,067,956** | **$7,540,065** |

# NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy Inc. and Subsidiaries consolidated statements of common stockholder's equity and other comprehensive income in Part II, Item 8.

*Basis of Presentation* — The condensed financial information of the holding company of Xcel Energy is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy's investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

Cash dividends paid to Xcel Energy by subsidiaries were $694 million, $759 million, and $566 million in the three years ended Dec. 31, 2007, respectively.

See Xcel Energy Inc. notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

# SCHEDULE II

## XCEL ENERGY INC.
## And Subsidiaries
## Valuation and Qualifying Accounts
## Years Ended Dec. 31, 2007, 2006 and 2005

*(thousands of dollars)*

| | | Additions | | | |
|---|---|---|---|---|---|
| | Balance at beginning of period | Charged to costs and expenses | Charged to other accounts[1] | Deductions from reserves[2] | Balance at end of period |
| Reserve deducted from related assets: | | | | | |
| Allowance for bad debts: | | | | | |
| 2007 | $36,689 | $57,434 | $18,052 | $62,774 | $49,401 |
| 2006 | 39,798 | 56,919 | 16,022 | 76,050 | 36,689 |
| 2005 | 34,299 | 43,327 | 12,379 | 50,207 | 39,798 |

(1) Recovery of amounts previously written off.

(2) Principally bad debts written off or transferred.

# SIGNATURES

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

XCEL ENERGY INC.

February 20, 2008

By: /s/ BENJAMIN G.S. FOWKE III

Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
(Principal Financial Officer)

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

| | |
|---|---|
| /s/ RICHARD C. KELLY<br>RICHARD C. KELLY | Chairman, President and Chief Executive Officer<br>(Principal Executive Officer) |
| /s/ TERESA S. MADDEN<br>TERESA S. MADDEN | Vice President and Controller<br>(Principal Accounting Officer) |
| /s/ BENJAMIN G.S. FOWKE III<br>BENJAMIN G.S. FOWKE III | Vice President and Chief Financial Officer<br>(Principal Financial Officer) |
| *<br>C. CONEY BURGESS | Director |
| *<br>FREDRIC W. CORRIGAN | Director |
| *<br>RICHARD K. DAVIS | Director |
| *<br>ROGER R. HEMMINGHAUS | Director |
| *<br>A. BARRY HIRSCHFELD | Director |
| *<br>DOUGLAS W. LEATHERDALE | Director |
| *<br>ALBERT F. MORENO | Director |
| *<br>MARGARET R. PRESKA | Director |
| *<br>A. PATRICIA SAMPSON | Director |

| | | |
|---|---|---|
| * | ______________________________ | Director |
| | RICHARD H. TRULY | |
| * | ______________________________ | Director |
| | DAVID A. WESTERLUND | |
| * | ______________________________ | Director |
| | TIMOTHY V. WOLF | |
| * | /s/ TERESA S. MADDEN | |
| | TERESA S. MADDEN<br>Attorney-in-Fact | |

## SHAREHOLDER INFORMATION

**HEADQUARTERS**
414 Nicollet Mall, Minneapolis, Minnesota 55401

**INTERNET ADDRESS**
www.xcelenergy.com

**STOCK TRANSFER AGENT**
The Bank of New York Mellon Shareowner Services
480 Washington Boulevard
Jersey City, New Jersey 07310
Telephone: 1-877-778-6786, toll free
E-mail: xcelshareholders@bnymellon.com

**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. Click on Investor Information.

**STOCK EXCHANGE LISTINGS AND TICKER SYMBOL**
Common stock is listed on the New York Stock Exchange under the ticker symbol XEL. The New York Stock Exchange lists some of Xcel Energy's preferred stock. In newspaper listings, it appears as XcelEngy.

**INVESTOR RELATIONS**
Internet address: www.xcelenergy.com or contact Paul Johnson, Managing Director, Investor Relations, and Assistant Treasurer, at 612-215-4535 or Jack Nielsen, Director, Investor Relations, at 612-215-4559.

**SHAREHOLDER SERVICES**
Internet address: www.xcelenergy.com or contact Dianne Perry, Manager, Shareholder Services, at 303-294-2362 or e-mail dianne.g.perry@xcelenergy.com

**CORPORATE GOVERNANCE**
Xcel Energy has filed certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2007 that it has filed with the Securities and Exchange Commission. It has also filed with the New York Stock Exchange the CEO certification for 2007 required by section 303A.12(a) of the New York Stock Exchange's rules relating to compliance with the New York Stock Exchange's corporate governance listing standards.

## FISCAL AGENTS

**XCEL ENERGY INC.**
Transfer Agent, Registrar, Dividend Distribution, Common and Preferred Stock
BNY Mellon Shareowner Services, 480 Washington Boulevard, Jersey City, New Jersey 07310

Trustee – Bonds
Wells Fargo Bank Minnesota, N.A., Sixth Street and Marquette Avenue, Minneapolis, Minnesota 55479

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

## XCEL ENERGY DIRECTORS

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

**Fredric W. Corrigan** [2, 4]
Retired CEO and President, The Mosaic Company

**Richard K. Davis** [3, 4]
President and CEO, U.S. Bancorp

**Roger R. Hemminghaus** [1, 3]
Retired Chairman and CEO, Ultramar Diamond Shamrock Corporation

**A. Barry Hirschfeld** [2, 4]
Chairman, National Hirschfeld LLC

**Richard C. Kelly** *
Chairman, President and CEO, Xcel Energy Inc.

**Douglas W. Leatherdale** [1, 2]
Retired Chairman and CEO, The St. Paul Companies, Inc.

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

**Dr. Margaret R. Preska** [1, 3]
Owner and CEO, Robinson Preska Management Company
Distinguished Service Professor, Minnesota State Colleges and Universities, President Emerita, Minnesota State University—Mankato

**A. Patricia Sampson** [3, 4]
President and CEO, The Sampson Group, Inc.

**Richard H. Truly** [2, 4]
Retired U.S. Navy Vice Admiral

**David A. Westerlund** [1, 2]
Executive Vice President, Administration and Corporate Secretary, Ball Corporation

**Timothy V. Wolf** [1, 3]
Vice President and Global Chief Financial Officer, Molson Coors Brewing Company

Board Committees:
1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Nuclear, Environmental and Safety

*Richard C. Kelly is ex officio member of all committees


414 Nicollet Mall
Minneapolis, MN 55401
xcelenergy.com





08-02-229 | 2/2008 | CSS#0208