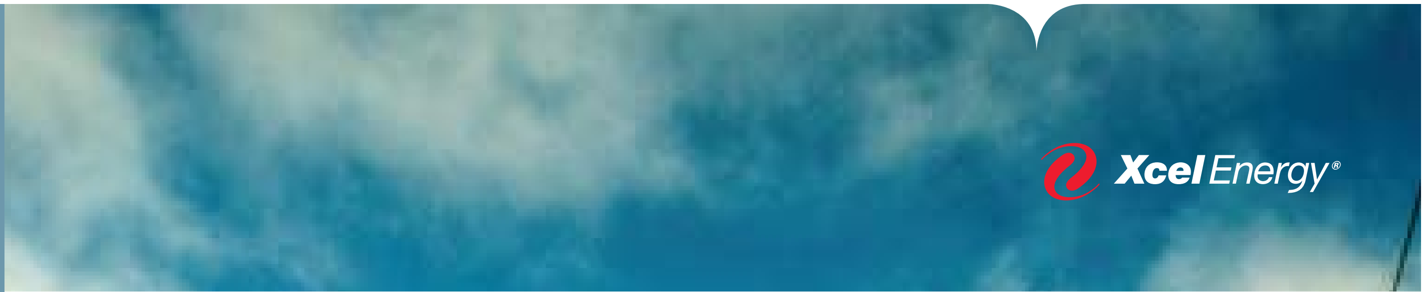


Xcel Energy®

Responsible By Nature™

2008 Annual Report

Helena Haynes-Carter, director, Diversity

Diversity and inclusion are part of Xcel Energy's value system and fundamental in creating a welcoming and respectful working environment.

ON THE COVER: Steve Engebretson, journeyman lineman

Xcel Energy employees such as Steve Engebretson are dedicated to customers and illustrate every day that they are ***Responsible By Nature™***.

Company **description**

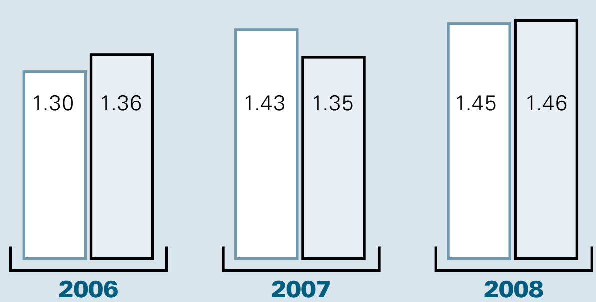
Xcel Energy is a major U.S. electric and natural gas company, with annual revenues of $11.2 billion. Based in Minneapolis, Minn., Xcel Energy operates in eight states. The company provides a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

Financial highlights

	2008	2007
Ongoing earnings per share	1.45	1.43
Total GAAP earnings per share	1.46	1.35
Dividends annualized	0.95	0.92
Stock price (close)	18.55	22.57
Assets (millions)	24,958	23,185
Book value per common share	15.35	14.70

Xcel Energy **earnings per share**

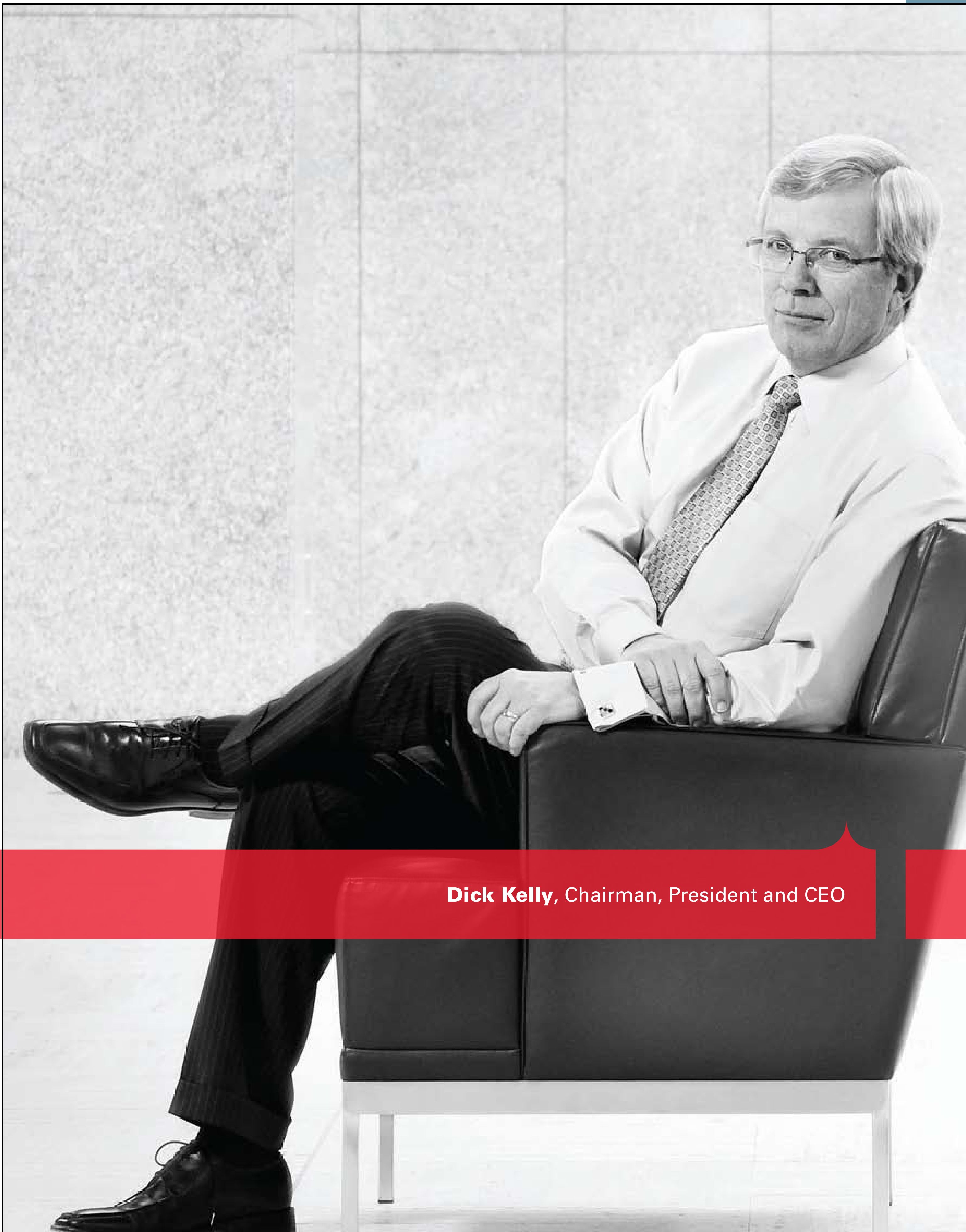
Dollars per share (diluted)



Ongoing earnings per share

GAAP (generally accepted accounting principles) earnings per share

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.



Dick Kelly, Chairman, President and CEO

Dear **Shareholders**

Despite the challenges of a global financial crisis and economic downturn, Xcel Energy delivered solid results in 2008. We met the majority of our financial targets, including our dividend goal. We continued to invest in our core businesses to meet customer energy needs and build long-term value for you. And we remained strongly committed to environmental leadership and the health of our communities.

Responsible By Nature™, the theme of this report and our new corporate tagline, describes Xcel Energy's long-standing approach to all of our commitments. Simply put, responsibility is part of everything we do. We take our obligations to shareholders, customers and our communities seriously—and our results prove that we work hard to deliver on our goals.

Delivering financial results

Ongoing earnings for 2008 were $1.45 per share, compared with $1.43 per share in 2007. That means we met the lower end of our earnings guidance range of $1.45 to $1.50 per share, but fell short of our long-term earnings growth objective of 5 percent to 7 percent.

Several factors affected 2008 results. We benefited from additional revenue from rate cases and other regulatory rules. But we also experienced slowing sales growth. In fact, weather-adjusted residential sales were flat for the year.

Because we closely monitor projected earnings throughout the year, we were able to take steps to ensure we would meet our 2008 target. The most notable action was to eliminate our annual incentive compensation for employees.

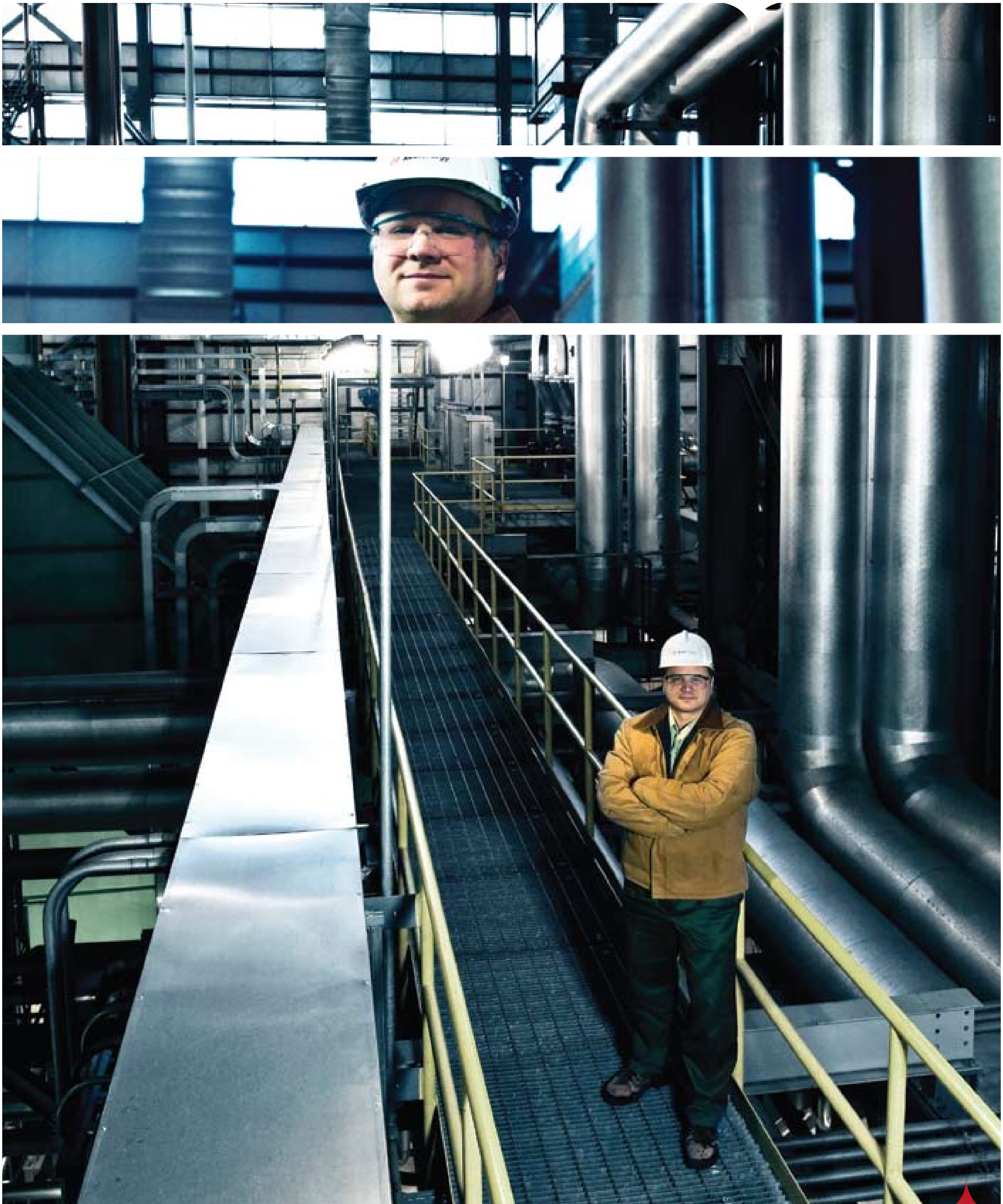
We were fortunate to raise $2.3 billion in financing before the market collapse, which will enable us to continue to invest in our businesses, despite challenges in the capital markets. And we benefited from improved credit ratings from Standard & Poor's, which upgraded the senior unsecured credit ratings at three of our operating companies.

Most important to you, we increased our dividend by 3 cents per share, or 3 percent. That means we met our goal to increase the dividend every year by 2 percent to 4 percent, which remains our long-term objective.

Looking ahead to 2009, we've established an earnings guidance range of $1.45 to $1.55 per share. If we achieve the midpoint of that range, we will be delivering modest growth compared with our long-term objective. But we also believe that as soon as the economy returns to a normal level of productivity, we will be in a strong position to resume our long-term earnings growth rate.

Keeping our **commitments**

We continued to execute our corporate strategy to meet customer needs and grow our businesses through environmental leadership. Meeting the need for reliable energy requires significant investments, 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.



Jim Zyduck, plant director, High Bridge

As part of a major effort to reduce emissions, Xcel Energy converted its High Bridge generating plant from a coal-fired to a natural gas facility. In addition to improving the environment, the conversion added generating capacity to the plant.

As part of that strategy, we reached satisfactory conclusions in 2008 in regulatory cases in Wisconsin and North Dakota, and filed additional rate cases in Minnesota, Colorado and New Mexico, which should add revenue this year. We also are making excellent progress on several large construction projects.

In Minnesota, we completed the conversion of our High Bridge plant from a coal-fired to a natural gas facility. The project is part of a larger emission-reduction effort that included completely refurbishing our coal-fired King plant and ongoing work to convert our Riverside plant from coal to natural gas. Overall, the effort, which should be complete this year, adds about 300 megawatts of generating capacity while significantly reducing emissions.

In Colorado, work progressed on Comanche 3, a 750-megawatt generating unit at our Comanche coal-fired facility near Pueblo that should be operational this year. 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.

Significant investment in our transmission system prepares us for a clean energy future. With new construction and various upgrades, we will be able to deliver much more renewable energy than ever before. In Minnesota and Colorado, we are working with other energy companies to develop transmission plans to meet regional needs. In Texas, we are strengthening our transmission system to support strong agricultural and industrial demand for electricity in the Panhandle and accommodate more wind interconnections.

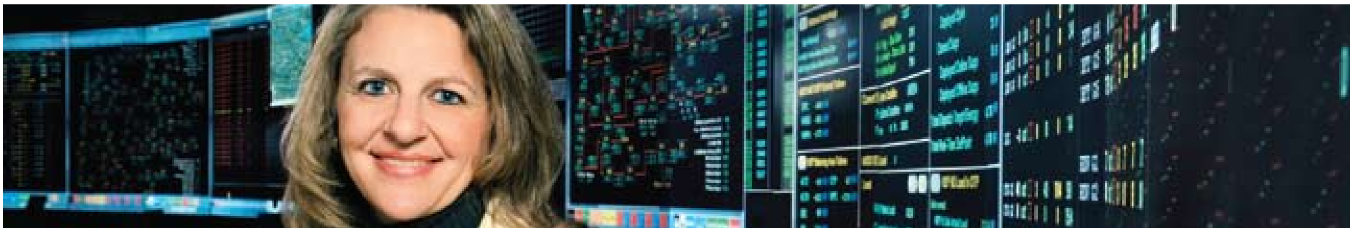
Once again, our large capital projects provide opportunities to build financial value for you, while increasing reliability and improving the environment.

Caring for the **environment**

In fact, environmental leadership drives all of our energy resource decisions, and our record illustrates the strength of that commitment.

For the third year in a row, Xcel Energy was the No. 1 provider of wind energy in the nation, according to the American Wind Energy Association. We had almost 3,000 megawatts of wind energy on our system at the end of 2008, with plans to include about 7,400 megawatts by 2020. And we launched an effort to own more of that wind energy when our 100-megawatt Grand Meadow wind farm began commercial operations at the end of the year. We also signed contracts for the development of another 351 megawatts of owned wind in southwestern Minnesota and North Dakota.

We are making great strides in the solar arena, too. We're No. 5 in the nation for solar power capacity and manage a fast-growing program in Colorado called Solar*Rewards that offers rebates to residential and business customers for installing on-site solar systems. Applications for the program increased significantly last year, and we are expanding the effort to New Mexico. We also announced plans to acquire up to 600 megawatts of concentrating solar power, with



Sandy Simon, director, Utility Innovations and Smart Grid Strategy

The company is exploring smart grid technologies that will enable customers to better manage their energy use and give Xcel Energy more options to monitor and operate its electric system.

storage capability. Having the ability to store the solar power will enable us to use the energy when we need it most.

On another renewable energy front, we are planning to install innovative biomass gasification technology on an existing coal-fired unit at our Bay Front plant in Wisconsin. The project would make Bay Front the largest biomass plant in the Midwest and one of the largest in the nation. Pending regulatory approval, engineering and design work would begin in 2010 and the project would be complete in late 2012.

Environmental leadership is an important consideration as we invest in our nuclear plants, which are safe and reliable, with no greenhouse gas emissions. We've filed applications to renew the operating licenses of two units at our Prairie Island facility, and to make modifications to increase the generating capacity of both our Prairie Island and Monticello nuclear plants. In addition, we are seeking to add more storage for spent nuclear fuel at Prairie Island.

Of course, one of the most effective ways to protect the environment is to work with customers to save energy and manage its use, which we've done for more than two decades. In a time of rising energy prices, conservation is the best way for customers to manage their energy costs. Although our conservation effort is significant and long-standing, we are increasing it to meet growing standards in our service territory.

Taking advantage of **new technology**

As our renewable energy portfolio grows and environmental regulations increase, we are exploring new technologies to enable us to fully realize our environmental goals. In Minnesota, we are testing the ability of large batteries to store wind power, which is a promising effort. As with solar power, one of the challenges of wind power is its intermittency. If we could store the electricity and use it when we need it most, we could address that challenge. We also are working to discover better ways of predicting the amount of electricity a wind farm can generate at any one time.

On the solar energy front, we've collaborated with partners to form the Solar Technology Acceleration Center, a world-class facility focused on commercializing new solar energy technologies.

In Colorado, we are testing a variety of smart grid technologies in Boulder, which we've designated as our SmartGridCity™. The technologies allow two-way communication with customers and give those customers many options for managing their energy use. They can decide, for example, when to operate their appliances based on cost or environmental considerations. They can go online to determine how much energy they're using at a particular time of day. A smart grid benefits Xcel Energy as well, allowing us to better manage our own system. For example, we can use networking technology to monitor and react to what's happening at any given moment, which improves efficiency and prevents outages.

Responsible By Nature™

We feature employee profiles in this report and the accompanying DVD because the people of Xcel Energy embody the company's responsibilities. Our line crews, for example, illustrate their commitment to customers every time they are called to repair damage after a storm and work around the clock in all weather conditions. The employees who diligently work behind the scenes on regulatory filings, accounting ledgers or legislative reports are just as focused on our commitments.

Throughout 2008, an employee-driven effort called the Performance Excellence Program (PEP) took a comprehensive look at how Xcel Energy operates—finding efficiencies and ways to reduce costs and increase productivity. The PEP effort, which continues this year, is another example of Xcel Energy employees focusing on making Xcel Energy the best utility it can be.

Our employees and retirees also care about our communities. Even in a tough economy, they pledged more than $2.6 million to support local United Way efforts. Xcel Energy matches those pledges dollar for dollar, giving more than $5.2 million to United Way in our latest effort. Our employees also are excellent volunteers, donating their time and talents to a wide range of organizations.

In addition, Xcel Energy supports the community through Xcel Energy Foundation grants, in-kind donations to nonprofit organizations and matching gifts. Those contributions, combined with our environmental leadership, enabled us to make the Dow Jones Sustainability Index (DJSI) for North America for the third year in a row. Companies listed on the DJSI are considered to be best in class in economic, environmental and social performance.

Moving **forward**

Looking to the future, we will continue to meet customer needs and grow our businesses through environmental leadership, while delivering on our financial objectives. Our commitments won't change. At the same time, we will closely monitor economic conditions, remaining flexible and ready to act on any opportunity or challenge. In today's economic environment, it's important to maintain a strong balance sheet, and we will do that. Those efforts will enable us to stay strong and continue to build value for you. As always, we appreciate your trust and support.

Finally, we would like to thank three members of our board of directors who are leaving the board this year. Douglas Leatherdale, Roger Hemminghaus and A. Barry Hirschfeld have served us well for many years. We sincerely appreciate their valuable contributions and wish them well.

Sincerely,

Richard C. Kelly
Chairman, President and CEO

Responsible By Nature™

We invite you to view ***Responsible By Nature™***, a DVD that features Xcel Energy employees who are committed to their customers, their communities and the environment. The DVD also includes profiles of Chairman, President and CEO Dick Kelly and Executive Vice President and CFO Ben Fowke.

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 December 31, 2008

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	**41-0448030**
State or other jurisdiction of Incorporation or organization	(I.R.S. Employer Identification No.)

414 Nicollet Mall,
Minneapolis, MN 55401
(Address of principal executive offices)

Registrant's Telephone number, including area code: 612-330-5500

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

Title of each class	Name of each exchange on which registered
Common Stock, $2.50 par value per share	New York
Rights to Purchase Common Stock, $2.50 par value per share	New York
Cumulative Preferred Stock, $100 par value:	
Preferred Stock $3.60 Cumulative	New York
Preferred Stock $4.08 Cumulative	New York
Preferred Stock $4.10 Cumulative	New York
Preferred Stock $4.11 Cumulative	New York
Preferred Stock $4.16 Cumulative	New York
Preferred Stock $4.56 Cumulative	New York
7.60 Junior Subordinated Notes, Series due 2068	New York

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in 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 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 Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's 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 Exchange Act. ☒ 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, 2008, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $8,648,495,720 and there were 430,916,578 shares of common stock outstanding.

As of Feb. 23, 2009, there were 454,218,905 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2009 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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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, a joint venture formed with a subsidiary of El Paso Corporation to develop and lease natural gas pipeline, storage, and compression facilities
Xcel Energy	Xcel Energy Inc., a Minnesota corporation
Federal and State Regulatory Agencies	
CAPCD	Colorado Air Pollution Control Division
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
MPCA	Minnesota Pollution Control Agency
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 Corporation. A self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and government authorities in Canada, to develop and enforce reliability standards.
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.
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.
OATT	Open Access Transmission Tariff
PCCA	Purchased capacity cost adjustment. Allows PSCo to recover from retail customers for all purchased capacity payments to power suppliers, effective Jan. 1, 2007. Capacity charges are not included in PSCo's 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 the PSCo electric utility provides for bill credits to customers based on operational performance standards through Dec. 31, 2010. The QSP for the PSCo natural gas utility also expires December 2010.
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 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. Obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.
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
CapX 2020	An alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort.
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: • An underlying and a notional amount or payment provision or both, • 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 • 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
FASB	Financial Accounting Standards Board

Fitch	Fitch Ratings
FTRs	Financial Transmission Rights. Used to hedge the costs associated with transmission congestion.
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 MW (capacity) or MW hours (energy).
GHG	Greenhouse Gas
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.
native load	The customer demand of retail and wholesale customers that 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. The tariff requires RTOs such as the MISO to provide real-time energy imbalance services and a market-based mechanism for congestion management.
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.
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. One gigawatt hour equals one billion watt hours.
KV	Kilovolts (one KV equals one thousand volts)
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.

COMPANY OVERVIEW

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2008, 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 joint venture formed with a subsidiary of El Paso Corporation to develop and lease natural gas pipeline, storage, 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, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are 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.

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 Colorado and Minnesota, which are intended to result in a significant reduction in GHG 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 renewable energy mandates and take advantage of 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 9 percent of its total sales in 2008. 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 89 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2008. Generally, NSP-Minnesota's earnings range from 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 Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System.

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 its total sales in 2008. 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 248,000 customers and natural gas utility service to approximately 104,000 customers. The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2008. Generally, NSP-Wisconsin's earnings range from 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 22 percent of its total sales in 2008. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers 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 2008. Generally, PSCo's earnings range from approximately 40 percent to 55 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 owns 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 39 percent of its total sales in 2008. SPS provides electric utility service to approximately 393,000 customers. Approximately 77 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2008. Generally, SPS' earnings range from 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 formed as a joint venture with a subsidiary of El Paso Corporation to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. Xcel Energy has invested approximately $128 million as of Dec. 31, 2008, for construction of WYCO's High Plains gas pipeline and the related Totem gas storage facilities. Xcel Energy plans to invest an additional $46 million in these projects in 2009 and 2010. The High Plains gas pipeline began operations in late 2008 and the Totem gas storage facilities are expected to begin operations in 2009. The gas pipeline and storage facilities will be leased under a FERC-approved agreement to Colorado Interstate Gas Company, a subsidiary of El Paso Corporation.

Xcel Energy Services Inc. is the service company for the Xcel Energy holding company system.

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 in Note 20 to the consolidated financial statements.

Xcel Energy had several other subsidiaries that were sold or divested. For more information regarding Xcel Energy's discontinued operations, see Note 4 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 are set forth in Note 20 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 or establishes formula rate or automatic rate adjustment mechanisms 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 17 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. Further, 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. Numerous states 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 and regulations. 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, legislation, and regulation, 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. In 2008, the FERC approved a MISO proposal to begin operation of a regional Ancillary Services Market (ASM) in January 2009.

Xcel Energy supports the continued development of wholesale competition and non-discriminatory wholesale open access transmission services. NSP-Minnesota received MPUC approval in 2008 to construct three new 115 KV transmission lines in 2009 to deliver additional wind generation even if NSP-Minnesota does not purchase the generation. SPS is also 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.

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 generating and transmission facilities, and the siting and routing of 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 for monthly billing adjustments 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 approved by the regulators in each jurisdiction.

The FCAs 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 general, capacity costs are not recovered through the FCA. In December 2006, the MPUC authorized FCA recovery of all MISO Day 2 charges, except certain administrative charges, which NSP-Minnesota partially recovered in base rates and partially deferred for future recovery in its 2009 Minnesota electric rate case. The SDPUC and the NDPSC have authorized FCA recovery of MISO Day 2 charges. In 2008, NSP-Minnesota requested that the MPUC, NDPSC and SDPUC allow FCA treatment of all MISO ASM charges and revenues effective with the start of the ASM on Jan. 6, 2009. The SDPUC approved the request on Feb. 12, 2009. The NDPSC has concluded that the recovery was addressed and permitted through the recent rate case settlement. NSP-Minnesota will hear the matter on Feb. 26, 2009. 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. The second project at the High Bridge plant went into service in May 2008. The remaining project at the Riverside facility is expected to begin operations in 2009. 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 with a range of 9.87 to 11.47 percent, 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, 2008, the estimated ROE was 10.71 percent, based on construction progress to date.

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 2009, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2006	2007	2008	2009 Forecast
NSP System	9,859	9,427	8,697	9,662

The peak demand for the NSP System typically occurs in the summer. The 2008 system peak demand for the NSP System occurred on July 29, 2008.

Energy Sources and Related Transmission Initiatives

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

Purchased Power **—** NSP-Minnesota has contracts 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 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 contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

Excelsior Energy **—** 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 1 and a second 600 MW unit in Phase 2 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 among other things, that Excelsior and NSP-Minnesota should resume negotiations toward an acceptable purchase power agreement, with assistance from the Minnesota Department of Commerce (MDOC) and the guidance provided by the order.

On Sept. 24, 2008, the MPUC denied Excelsior Energy's Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW IGCC facility. The MPUC also set a May 1, 2009 deadline for Phase 1 of the proceeding in which it had previously ordered negotiations. On Oct. 14, 2008, Excelsior sought rehearing of the MPUC's Sept. 24, 2008 order. On Dec. 9, 2008, the MPUC held further action in abeyance until after the May 1, 2009 deadline.

GHG Emissions **—** The 2007 Minnesota legislature adopted the goal to reduce statewide GHG emissions across all sectors 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 also 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 provides for 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 (RES)* —** The 2007 Minnesota legislature adopted a RES statute requiring that 30 percent of NSP-Minnesota's energy requirements by 2020 come from qualifying renewable sources, primarily wind energy. Costs associated with complying with the standard are recoverable through automatic recovery mechanisms.

NSP-Minnesota has filed with the MPUC a renewable energy plan 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.

***2008 Minnesota Legislative Session* —** The 2008 Minnesota legislature considered and adopted several measures related to energy policy and regulation, including:

- Encouraging Minnesota's participation in the Midwest Governors' Association's GHG accord and commissioning of an economic study of the potential impacts of a carbon cap-and-trade program;
- Modifying the existing TCR mechanism to allow for recovery of costs associated with MISO charges for regional transmission expansion;
- Providing for recovery via a rate rider mechanism of certain energy storage projects associated with renewable energy projects; and
- Providing for a streamlined approval process for wind and solar projects needed to comply with Minnesota's RES.

The legislature considered, but did not adopt, increased taxes on utility property.

***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 provisions of the plan include the following:

- Adding 2,600 MW of wind generation resources 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 and capacity upgrades at Sherburne County (Sherco). 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 MW.
- Carbon emission reductions of 22 percent below 2005 levels by 2020.

In June 2008, intervenors filed comments on this plan. The Minnesota Office of Energy Security (OES) recommended approval, subject to further expansion of DSM goals. Environmental intervenors recommended expanded DSM goals and expressed concerns regarding carbon management with the proposed expansion of certain coal resources. Excelsior Energy recommended inclusion of its proposed project in the plan. The Prairie Island Community expressed health and safety concerns regarding nuclear resources. The Minnesota Chamber of Commerce expressed interest in cost and rate management. NSP-Minnesota filed reply comments in September 2008 providing updated information, including a revised forecast. As discussed below, it also withdrew its request for upgrades at Sherco Units 1 and 2. The MPUC is expected to act on the plan in the first half of 2009.

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. The disclosure regarding the Monticello and Prairie Island plans is included below under "Nuclear Power Operations and Waste Disposal."

In December 2007, NSP-Minnesota filed a plan for major pollution control and efficiency improvements at Sherco Units 1 and 2 with the MPUC. The plan proposed conversion of the pollution control systems at the plant from wet scrubber precipitator technology to dry spray absorber/baghouse equipment as well as efficiency improvements that would increase the production capacity of the plant by 70 MW. The total cost of the proposed plan was estimated at $1 billion. In November 2008, NSP-Minnesota filed a request with the MPUC to withdraw the plan to reevaluate alternatives, due to significant changes in the national economy, lower forecast of energy consumption, and new information concerning an emerging technology that may be more cost effective. The MPUC granted the withdrawal request on Dec. 9, 2008.

Wind Generation — In December 2008, the first NSP-Minnesota owned wind generation plant, the 100 MW Grand Meadow wind farm, went into service. The project was developed through a build-own-transfer arrangement with a large wind energy developer (enXco) at a cost of approximately $210 million. NSP-Minnesota plans to invest approximately $900 million over three years for a 201 MW project in southwestern Minnesota, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project. These projects are expected to be operational by the end of 2010 and 2011, respectively. On Dec. 3, 2008, NSP-Minnesota filed petitions with the MPUC and the NDPSC seeking the required regulatory approvals for the two wind powered generating facilities. See additional discussion of wind generation, in Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations.

NSP-Minnesota Transmission Certificates of Need — In August 2007, NSP-Minnesota and Great River Energy (on behalf of eight other regional transmission providers) filed a certificate of need application, for three 345 KV transmission lines, as part of the CapX 2020 project. The project to build the three lines includes construction of approximately 600 miles of new facilities at a cost of approximately $1.7 billion, with construction to be completed in phases. The cost of the project to NSP-Minnesota and NSP-Wisconsin is estimated to be approximately $900 million. These cost estimates will be revised after the regulatory process is completed. Evidentiary hearings were completed in September 2008. The OES recommended an increase in capacity for the Fargo, N. D. project. An environmental coalition supported the projects subject to conditions for wind purchases or commitments for the transmission capacity, while two other intervenors opposed the proposal. The applicants filed rebuttal testimony recommending the modification of all three projects to be constructed as double circuit compatible with the first circuit strung during initial construction and the second circuit strung as needed. NSP-Minnesota expects the ALJ to issue a report and recommendation in the first quarter of 2009. The MPUC is expected to make a final decision in 2009 after receipt of the ALJ report.

As part of CapX 2020, Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative (on behalf of themselves and NSP-Minnesota and Great River Energy) filed a certificate of need application in March 2008 for a 230 KV transmission line between Bemidji and Grand Rapids, Minn. A route application for this project was filed in June 2008. The need application is uncontested; route hearings are expected to be conducted in late 2009, and an MPUC decision is anticipated by the second quarter of 2010. The Bemidji-Grand Rapids line is expected to entail construction of approximately 68 miles of new facilities at a cost of $100 million, with construction to be completed by end of 2011. The estimated cost to NSP-Minnesota is approximately $26 million.

In the second quarter of 2009, NSP-Minnesota plans to file a certificate of need application with the MPUC for two 161 KV transmission lines in the Rochester, Minn. area to support ongoing development of wind powered generation in southeastern Minnesota. The proposal consists of an approximately 15 mile long, 161 KV transmission line north of Rochester, and an approximately 30 mile long, 161 KV transmission line southeast of Rochester. The project's estimated cost is $30 million. An MPUC decision is anticipated late in 2009.

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 comments. 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 ongoing.

***Mercury Reduction and Emissions Reduction Filings* —** In December 2007, NSP-Minnesota filed a plan with the MPCA and MPUC for reducing mercury emissions at the Sherco Unit 3 and A. S. King plants. Currently, the estimated project costs are approximately $8.5 million. The MPUC has approved the mercury control plans. Implementation will begin in 2009. NSP-Minnesota plans to seek cost recovery of mercury control investments through an automatic rate adjustment mechanism (rate rider) filing later in 2009. As discussed above, NSP-Minnesota is reexamining its plans for emission controls at Sherco Units 1 and 2 and anticipates submitting an alternative mercury control plan with the MPUC in 2009.

***Nuclear Power Operations and Waste Disposal* —** NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant, which has two units. See additional discussion regarding the nuclear generating plants at Note 18 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 (LLW) consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

LLW Disposal — Federal law places responsibility on each state for disposal of 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 had an annual contract with Barnwell that expired 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 17 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. At the following dates, casks for storage were either authorized or casks were loaded and stored:

- 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. 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, 2008, there were 24 casks loaded and stored at the Prairie Island plant and 10 casks loaded and stored at the Monticello plant.

See Note 18 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. 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. 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.

Nuclear Plant Power Uprates and Life Extension — NSP-Minnesota is pursuing life extensions and capacity increases of all three of its nuclear 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 the replacement of the original steam generators, currently planned for replacement during the refueling outage in 2013. Capital investments for life cycle management and power uprate activities through 2008 have totaled over approximately $125 million. For the years 2009 through 2015, spending is estimated at over $1.0 billion. See additional discussion in Capital Requirements in Item 7A — Management's Discussion and Analysis.

NSP-Minnesota has filed two applications for certificates of need related to its nuclear generating facilities to obtain approval for these projects. The first addresses approximately 71 MW of power uprates at the Monticello plant. The MPUC approved the Monticello power uprate certificate of need in December 2008. NSP-Minnesota re-submitted its NRC application for the Monticello plant extended power uprate in November 2008, and the NRC's Sufficiency review of the license amendment re-submittal was completed in December 2008. Although this delays the extended power uprate process slightly, NSP-Minnesota does not anticipate a substantial delay in the project at this time. The operating life of the Monticello nuclear plant has already been extended through 2030.

The second application addresses both life extension and approximately 160 MW in power uprates at Prairie Island Units 1 and 2. In July 2008, the MPUC determined that the application was complete and referred it to an ALJ for contested case hearing. The Prairie Island Community has indicated its interest in the power uprate portion of the case and has expressed interest in revisiting its 2003 settlement with NSP-Minnesota, in which it agreed that certain concerns it may have regarding Prairie Island life extension would be addressed in the federal relicensing process.

In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years, until 2033 and 2034, respectively. The Prairie Island Indian Community (PIIC) filed contentions in the NRC's license renewal proceeding in August 2008. The PIIC request was referred to an Atomic Safety and Licensing Board (ASLB) for review. The ASLB has granted the PIIC hearing request and has admitted 7 of the 11 contentions filed. The resulting adjudicatory process and hearings are expected to add approximately 8 months onto the NRC's standard 22 month review schedule. Therefore the NRC is not expected to make a decision until late 2010. An application for a Certificate of Need to expand the spent fuel storage capacity at Prairie Island to support 20 additional years of operation was filed with the MPUC in May 2008. It is expected that the MPUC will act in late 2009, which would result in the MPUC decision being stayed during the 2010 session of the Minnesota legislature before going into effect.

NMC — On Sept. 28, 2007, NSP-Minnesota obtained 100 percent ownership in NMC. Accordingly, the results of operations of NMC and the estimated fair value of assets and liabilities were included in NSP-Minnesota's consolidated financial statements from the Sept. 28, 2007 transaction date. NSP-Minnesota has reintegrated its nuclear operations into its generation operations. The application to the NRC to transfer the nuclear operating licenses from NMC to NSP-Minnesota was completed on Sept. 22, 2008.

For further discussion of nuclear obligations, see Note 18 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 Generating Plants	Coal*		Nuclear		Natural Gas		Weighted Average Fuel
	Cost	Percent	Cost	Percent	Cost	Percent	Cost
2008	$1.73	58%	$0.56	39%	$10.09	3%	$1.55
2007	1.56	57	0.51	38	7.60	4	1.47
2006	1.12	59	0.46	38	7.28	3	1.08

* Includes refuse-derived fuel and wood

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risks Associated with Our Business.

Fuel Sources

Coal — Coal inventory levels may vary widely among plants. However, the NSP System normally maintains approximately 39 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2008 and 2007, were approximately 49 and 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's and NSP-Wisconsin's major coal-fired generating plants were approximately 11.0 and 12.4 million tons per year at Dec. 31, 2008 and 2007, respectively.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 100 percent of their coal requirements in 2009, 65 percent of their coal requirements in 2010 and 36 percent of their coal requirements in 2011. 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 100 percent of their coal requirements in 2009, 100 percent of their coal requirements in 2010 and 28 percent of their coal requirements 2011. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

Nuclear — 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.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2009, approximately 68 percent of the requirements for 2010, 80 percent of the requirements for 2011 through 2013, 47 percent of the requirements for 2014 through 2017, with no arrangements for 2018 and beyond. Contracts for additional uranium concentrate supplies are currently in various stages of negotiations that are expected to provide a portion of the remaining open requirements through 2012.
- Current contracts for conversion services cover 100 percent of the requirements through 2011 and approximately 56 percent of the requirements from 2012 through 2015, with no arrangements for 2016 and beyond.
- Current enrichment services contracts cover 100 percent of 2009 through 2012 requirements and approximately 60 percent of 2013 requirements. A contract for additional enrichment services is being negotiated to provide the remainder of coverage for open requirements in 2013. There are currently no arrangements for 2014 and beyond. Offers for enrichment services for supply contracts for 2014 and beyond are being reviewed.
- The fuel fabrication contract for Monticello was extended during 2007 to cover one additional reload in 2011. Request for proposals from the fuel fabrication vendors for additional supply for Monticello were distributed. Offers from fuel fabrication vendors are being reviewed with plans to enter into a contract with one of the vendors in 2009. Prairie Island's fuel fabrication is 100 percent committed to at least 2015.

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 2012. Some exposure to price volatility will remain, due to index-based pricing structures on the contracts.

Natural gas — 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 supply, transportation and storage contracts expire in various years from 2009 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, 2008, NSP-Minnesota's commitments related to supply contracts were $89 million and commitments related to transportation and storage contracts were approximately $652 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.

Bay Front Biomass Gasification — On Feb. 23, 2009, NSP-Wisconsin filed an application for a certificate of authority to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wis. Currently, two of the three boilers at Bay Front use biomass as their primary fuel to generate electricity. The proposed project will convert the existing coal-fired unit to biomass gasification technology allowing the plant to use 100 percent biomass in all three boilers. The project, estimated at $58 million, will require additional biomass receiving and handling facilities at the plant, an external gasifier, minor modifications to the plant's remaining coal-fired boiler and an enhanced air quality control system. The total generation output of the plant is not expected to change significantly as a result of the project. However, the project will improve the environmental performance of the plant and contribute towards state renewable energy standards in the region. Following all state regulatory approvals, engineering and design work is expected to begin in 2010, and the unit could be operational by late 2012. When complete, the Bay Front Power Plant will be the largest biomass-fueled power plant in the Midwest and one of the largest in the nation.

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 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 (RPS) — The Wisconsin legislature passed a 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 because 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, 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* — The ECA recovers fuel and purchase power costs. It also 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 can not exceed $11.25 million in any year. The ECA mechanism is revised quarterly. 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 for most power purchase agreements. 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* — Effective January 2003, 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, to reduce emissions and improve air quality in the Denver metro area.

- *DSMCA* — The DSMCA clause permits PSCo to recover DSM and interruptible service option credit (ISOC) costs and performance initiatives based on achieving various energy savings goals on an annual basis beginning Jan. 1, 2009.

- *Renewable Energy Standard Adjustment (RESA)* — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of 2.0 percent of the customer's total bill.
- *Wind Energy Service Adjustment* — The Wind Energy Service Adjustment provides for the recovery of costs associated with wind energy resources from those customers subscribed to the WindSource® program.
- *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 transmission investments.

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 2009, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2006	2007	2008	2009 Forecast
PSCo	6,757	6,950	6,903	6,958

The peak demand for PSCo's system typically occurs in the summer. The 2008 system peak demand for PSCo occurred on Aug. 1, 2008.

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 contracts with regional transmission service providers to deliver power and energy to PSCo's customers.

***Purchased Power* —** PSCo has contracts 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 35 to 45 percent of its total electric system energy needs for 2009 under long-term contracts and generate the remainder with PSCo-owned resources. 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. The CPUC issued its order in September 2008, which approved the following:

- Increase in wind portfolio of 850 MW by 2015. PSCo would then have a total of approximately 1,900 MW of wind power resources;
- Approximately 200 MW from a central solar thermal facility with storage, with possible option of acquiring up to 600 MW of solar thermal resources with storage as technology develops;
- Increase customer efficiency and conservation programs with plans to meet the CPUC goals of annual energy sales reductions to approximately 3,669 GWh, that would yield a demand savings in the range of 886 MW to 994 MW by 2020;
- Retirement of two older coal-burning plants (two units at Arapahoe and two units at Cameo), replacing the capacity with company owned resources, provided the costs are reasonable; and
- Reduce PSCo's CO_2 emissions by 10 percent below 2005 levels and for PSCo to propose additional reductions to achieve a 20 percent reduction by 2020 in its next plan.

In April 2008, the CPUC approved a certificate of public convenience and necessity application to build a new, company owned 260 MW combustion turbine project at the existing Fort St. Vrain generating station. Fort St. Vrain is scheduled to come on line in the second quarter of 2009. The Fort St. Vrain project will leave PSCo 123 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.

Construction continues on Comanche 3, a 750 MW pulverized coal-fired unit at the existing Comanche Station located near Pueblo, Colo. and installation of additional emission control equipment on the two existing Comanche Station units. 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 AFDC, 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. IREA will take ownership of 190 MW and Holy Cross will take ownership of 60 MW upon commercial operation.

RES — 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;
- 20 percent of retail sales by 2020; and
- 4 percent must be generated from solar renewable resources with half the solar resources being located at customers facilities.

The new law limits the net incremental retail rate impact from these renewable resource acquisitions as compared to non-renewable resources 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 forward rider mechanism.

PSCo Regulatory Policy Initiative — In March 2008 open meetings, the CPUC voted to open an investigatory docket that will review the current regulatory structure to determine if current utility incentives are aligned with state public policy objectives and to determine if the existing structure is internally consistent in achieving these objectives. In June 2008, a transmission investigatory docket, was opened to gather information on transmission planning in Colorado and transmission planning coordination with other states and utilities. In September 2008, the CPUC opened a customer incentives docket whose scope covers how regulatory structure and incentives influence customer decisions.

Several parties, including PSCo filed comments in the utility incentive docket in September 2008. The comments covered a wide array of issues, including the best method to deliver DSM services to customers and the implications to utilities of owned generation or generation acquired through power purchase agreements. The comments also raised questions regarding whether or not revisions should be made to the current regulatory structure to reduce regulatory lag.

ISOC Program **—** In November 2007, PSCo submitted a request to the CPUC for permission to expand its ISOC program to make it available to customers without demand history, drop the threshold for participation to 300 KW, allow customers to control load through their energy management system, increase credits and allow customers to limit the number of interruptions in a day. PSCo also sought approval for current recovery of those credits through the DSM adjustment clause. Lastly, PSCo sought 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. In June 2008, the ALJ assigned to the case approved expansion of the program and removed current recovery and incentives from the current case. The CPUC upheld the ALJ's recommendation through an initial decision. Three parties filed a request for rehearing, reargument or reconsideration on limited issues. The CPUC granted the request and held deliberations on Oct. 15, 2008. In its final order, the CPUC approved expansion of the program, higher credits and concurrent recovery effective Jan. 1, 2009.

RESA **—** In December 2008, PSCo filed a request with the CPUC 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. The CPUC approved the request, and the increase became effective on Jan. 1, 2009.

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		Weighted Average Fuel
	Cost	Percent	Cost	Percent	Cost
2008	$1.42	84%	$7.03	16%	$2.31
2007	1.26	84	4.34	16	1.76
2006	1.24	85	6.52	15	2.01

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risks Associated with Our Business.

Fuel Sources

Coal — Coal inventory levels may vary widely among plants. However, PSCo normally maintains approximately 35 days of coal inventory at each plant site. Coal supply inventories at Dec. 31, 2008 and 2007, were approximately 32 and 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 contracts with suppliers operating in Colorado and Wyoming. During 2008 and 2007, PSCo's coal requirements for existing plants were approximately 11 million and 10 million tons, respectively.

PSCo has contracted for coal suppliers to supply 100 percent of its coal requirements in 2009, 49 percent of its coal requirements in 2010 and 34 percent of its coal requirements in 2011. Any remaining requirements will be filled through an RFP process.

PSCo has coal transportation contracts that provide for delivery of 100 percent of its coal requirements in 2009, 93 percent of its coal requirements in 2010 and 93 percent of its coal requirements in 2011. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather, and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. The supply contracts expire in 2009 and 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, 2008, PSCo's commitments related to supply contracts were approximately $137 million and transportation and storage contracts were approximately $1 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.

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 regulations allow retail fuel factors to change up to three times per year.

The regulations also 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.

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 fuel and purchased energy costs at least every three years.

The NMPRC has authorized SPS to implement a monthly adjustment factor for a fuel and purchased power cost adjustment clause for SPS' New Mexico retail jurisdiction.

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 QSP requiring SPS to comply with electric service reliability performance targets. In October 2008, the PUCT staff served SPS with notice that it had initiated an investigation to determine whether SPS is in compliance with the Texas statutes and PUCT rules on reliability and continuity of service. NMPRC regulations require SPS to periodically file requesting authority to continue using its FPPCAC. In that proceeding, the NMPRC reviews SPS' use of its FPPCAC since the filing of its previous fuel clause continuation filing. SPS' next fuel clause continuation filing is due Aug. 26, 2010.

Texas Energy Efficiency Cost Recovery Factor (EECRF) Rider — PUCT regulations established the mechanism under which electric utilities may recover costs associated with providing energy efficiency programs. That mechanism, an EECRF Rider, must be included in a utility's tariff and may be established in a utility's base rate case or through a separate request seeking to establish an EECRF. In accordance with this rule, SPS has removed its energy efficiency costs from its recent base rate proceeding, and has requested implementation of its EECRF Rider to recover the remaining unamortized balance of historic costs and its projected 2008 and 2009 energy efficiency costs. In September 2008, the PUCT concluded that the rule under which the application was filed does not apply to SPS and the energy efficiency costs could be recovered in the pending Texas retail base rate case. SPS filed supplemental testimony in the currently pending Texas retail base rate case seeking cost recovery.

Texas Renewable Energy Zones — In 2007, the PUCT designated competitive renewable energy zones (CREZs), which are regions of the state that 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. On Aug. 15, 2008, the PUCT issued a final order identifying a transmission plan to deliver approximately 18,000 MW of wind energy to load centers in ERCOT. The plan includes lines in the Texas Panhandle. Cost of this transmission plan is almost $5 billion, not including collector lines, and it will be paid for by ERCOT customers, not by SPS. A proceeding is now underway at the PUCT to select transmission providers to construct CREZ lines and associated facilities. Designations of transmission service providers to construct CREZ transmission projects were made at the

PUCT open meeting on Jan. 29, 2009. In a unanimous decision, lines in Panhandle CREZs were assigned to Sharyland Utilities, Cross Texas Transmission and Wind Energy Transmission Texas (WETT). Priority lines located in central and west Texas CREZs were mostly assigned to Oncor and LCRA. These transmission providers will begin preparing certification applications.

New Mexico Energy Efficiency Disincentive Rulemaking — During the last legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. The NMPRC is currently holding a rulemaking to update the energy efficiency rule, consistent with the legislative changes.

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2009, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2006	2007	2008	2009 Forecast
SPS	4,711	4,731	4,996	5,122

The peak demand for the SPS system typically occurs in the summer. The 2008 system peak demand for SPS occurred on Aug. 5, 2008.

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 contracts 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 comply with minimum availability requirements, and to obtain energy at a lower cost.

SPS Resource Planning

Lea Power Partners (LPP) — LPP, which was late meeting its contractual commercial operation date, was officially declared commercial on Sept. 16, 2008. Because of the delay, SPS received approximately $12 million in delay damages. The Purchase Power Agreement (PPA), which was executed in 2006, provides for SPS to have exclusive rights to the facility for a period of 25 years. LPP's generation is a two-by-one natural gas combined cycle 604 MW plant located near Hobbs, N. M.

Integrated Resource Planning — SPS is required to file an Integrated Resource Plan (IRP) before the NMPRC on or before July 2009. Also as part of this mandate, SPS must initiate a public advisory process by July 2008. Meetings have occurred periodically since the July 2008 date and are expected to continue throughout 2009 up until the time the plan is filed in July 2009.

Renewable Energy Portfolio Plan — SPS is required to file its plan with the NMPRC by July 1, 2009, for meeting the calendar year 2010 RPS. This renewable energy portfolio plan is required to include minimums of 20 percent for wind energy, 20 percent for solar energy, and 10 percent for other renewable energy technologies, as defined within the rule. The rule also requires the following minimums for distributed generation: 1 and 1.5 percent for calendar years 2011 through 2014, and 3 percent beginning in calendar year 2015. SPS released a Non-Wind RFP on Feb. 1, 2008, to meet the above regulatory mandate. SPS is contemplating execution of certain commercial agreements on or before its next filing on or before July 2009.

Pending Resource Solicitations — SPS released four RFP's during 2008. The proposals target capacity and energy resources as follows; up to 200 MW under terms of 3 to 8 years with deliveries beginning either June 2010 or June 2011, up to 200 MW of wind resources located in the Texas portion of the SPS balancing authority, and up to 600 MW of dispatchable resources with terms of up to 20 years and deliveries beginning either June 2012 or June 2013. SPS expects to have finalized each of these solicitation efforts before the end of 2009 and may seek certain regulatory approvals of any resulting agreements.

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		Weighted Average Fuel
SPS Generating Plants	Cost	Percent	Cost	Percent	Cost
2008	$1.86	71%	$8.41	29%	$3.78
2007	1.64	67	6.45	33	3.22
2006	1.89	66	6.30	34	3.38

See additional discussion of fuel supply and costs under Item 7 — Factors Affecting Results of Continuing Operations in Management's Discussion and Analysis and under Item 1A — Risks Associated with Our Business.

Fuel Sources

Coal — 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 meet SPS' requirements. With oversight from Xcel Energy, 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, 2008, coal supplies at the Harrington and Tolk sites were approximately 43 and 45 days supply, respectively. TUCO has coal agreements to supply 100 percent of SPS' coal requirements in 2009, 85 percent of SPS' coal requirements in 2010, and 40 percent of SPS' coal requirements in 2011, which are sufficient quantities to meet the primary needs of the Harrington and Tolk stations.

Natural gas — SPS uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants are procured under contracts to provide an adequate supply of fuel. The supply contracts expire in 2009 and 2010. The transportation and storage contracts expire in various years from 2009 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, 2008, SPS' commitments related to supply contracts were approximately $15 million and transportation and storage contracts were approximately $271 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.

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 16 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 and 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 a number of rulemaking proceedings to modify its regulations on a number of subjects, including:

- Adopting regulations requiring NERC to establish mandatory electric reliability standards; and
- Certifying more than 120 NERC reliability standards mandatory and subject to potential financial penalties up to $1 million per day per violation for non-compliance. The FERC also approved certain WECC regional reliability standards as mandatory, which are applicable to PSCo.

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 Reliability Standards Compliance — The 2008 developments regarding reliability standards include the following:

Compliance Audits

The NSP System and PSCo were subject to electric reliability standards compliance audits in the first and second quarters of 2008, respectively. The Midwest Reliability Organization (MRO) found the NSP System in compliance with all NERC standards audited. In September 2008, the Western Electricity Coordinating Council (WECC) auditors issued a preliminary report finding PSCo possibly non-compliant with one of the standards for which PSCo was audited. The audit report is subject to further WECC procedures.

Compliance with NERC Protective Maintenance Standards

In April 2008, the NSP System, PSCo and SPS filed self-reports with the MRO, WECC and SPP, respectively, relating to failure to complete certain generation station battery tests required by NERC protective maintenance standards. Based on preliminary discussions with the MRO, Xcel Energy expects that penalties may be assessed by certain of the NERC regional entities in conjunction with the self-reports related to incomplete generation station battery tests. The penalties are not expected to be material.

In June 2008, as a follow-up to the WECC compliance audit, PSCo filed a self-report with WECC regarding violations of its relay maintenance plan. These reviews also found a lack of complete maintenance documentation for relays on the NSP System and SPS system. The NSP System and SPS self-reported the NERC standards violations to the MRO and SPP respectively. As required by NERC procedures, PSCo, NSP, and SPS also filed mitigation plans with the regional entities to correct the testing deficiencies. The PSCo and SPS mitigation plans are complete and the NSP mitigation plan is in progress.

In September 2008, as a result of a review of its procedures implementing certain NERC critical infrastructure protection standards applicable to control centers effective July 1, 2008, PSCo, the NSP System and SPS filed self-reports disclosing certain deficiencies in requirements applicable to access to critical cyber assets to the WECC, MRO and SPP, respectively. PSCo, the NSP System and SPS filed mitigation plans within 30 days from the date of the self-reports discussing how the deficiencies were corrected.

Except as noted, Xcel Energy is uncertain if the WECC compliance audit of PSCo or the NERC standards violations self-reported in 2008 will result in financial penalties. If so, the penalties are not expected to be material.

MRO/NERC Compliance Investigation

In March 2008, NSP-Minnesota received notice that the MRO was commencing a compliance investigation of the Sept. 18, 2007 event, when portions of the NSP System briefly islanded from the rest of the Eastern Interconnection, as a result of a series of transmission line outages. Because the event affected more than one region, the NERC took over the investigation. The final outcome of the NERC compliance investigation is unknown at this time. Given the ongoing investigation, Xcel Energy is unable to determine if the outcome of this matter will result in any finding of standards violations, and if so whether any associated penalties will have a material adverse impact on operations, cash flows or financial condition.

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 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 is expected to provide certain regionalized transmission services in the first quarter of 2009 and may provide wholesale energy market functions in the future, but would not be an RTO.

In February 2007, the FERC issued final rules (Order No. 890) adopting revisions to its open access transmission service rules. In December 2007, the FERC issued an order on rehearing (Order No. 890-A) making certain modifications to Order No. 890, effective in March 2008. In June 2008, the FERC issued a further order on rehearing (Order No. 890-B) making certain additional modifications to Order Nos. 890 and 890-A effective in September 2008. Xcel Energy has submitted several compliance filings to modify its OATT to reflect the modified FERC rules.

Certain transmission service customers objected to aspects of the Xcel Energy Order No. 890, 890-A and 890-B compliance filings. The various compliance filings are pending final FERC action.

Under Order No. 890, transmission providers are required to post certain information on their OASIS systems. In June 2008, the FERC initiated an audit of PSCo's Order No. 890 OASIS compliance postings. PSCo was one of several electric utilities notified that the FERC was commencing such an audit. In November 2008, the FERC issued an order requiring certain compliance actions but did not impose financial penalties. PSCo concurred with the audit report, and the audit is now completed.

The FERC issued proposed rules to modify the current standards of conduct rules governing the functional separation of the Xcel Energy electric transmission function from the wholesale sales and marketing function. On Oct. 16, 2008, the FERC issued revised final rules. On Dec. 15, 2008, the FERC extended the compliance deadline for certain compliance actions to Jan. 30, 2009. Xcel Energy is taking actions to be compliant with the revised rules.

Centralized Regional Wholesale Markets — The FERC rules allow RTOs to operate centralized regional wholesale energy markets. In April 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 designed 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 balancing market for the region that includes the SPS system.

In September 2007, MISO filed for FERC approval to establish a centralized regional wholesale ASM in 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 February 2008, the FERC issued an order conditionally approving the ASM tariff, but requiring certain changes. In December 2008, the FERC issued orders approving the MISO filings necessary for MISO to start the ASM. MISO began ASM operations in January 2009. To date, the ASM has generally functioned as anticipated.

In December 2007, MISO filed proposed changes to the TEMT (called Module E) to establish a long-term resource adequacy proposal. The proposal contains mandatory requirements for any market participant serving load in the MISO region, including the NSP System, to have and maintain access to sufficient resources to meet adequacy standards. The resources used to meet a resource adequacy requirement may include self-generation capacity, firm purchased power and demand response capability.

Under the Module E proposal, MISO will establish a Planning Reserve Margin for each Load-Serving Entity (LSE). The MISO resource adequacy tariff would replace the NSP System current planning reserve obligations. In March 2008, the FERC issued an order approving the Module E tariff. Various parties requested rehearing of the FERC order. MISO is expected to start Module E on March 1, 2009.

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 utility subsidiaries has been granted market-based rate authority and will be subject to the new rule. The Xcel Energy utility subsidiaries may not sell power at market-based rates within the PSCo and SPS balancing authorities, where they have been found to have market power under the FERC's applicable analysis. Both PSCo and SPS have cost-based coordination tariffs that they may use to make sales in their balancing authorities.

The FERC's market rate orders allow mitigated utilities such as PSCo and SPS to sell at their borders at market-based rates subject to certain conditions. Requests for rehearing addressing that aspect of the FERC's market-based rate orders are presently pending. Because PSCo makes such border sales, Xcel Energy sought such clarification from the FERC. The outcome of the rehearing request may impact the Xcel Energy utilities subsidiaries' continued ability to make such border sales at market-based rates.

Affiliate Transaction Rules — On Feb. 21, 2008, the FERC issued Order No. 707, which amended the FERC's regulations to codify restrictions on affiliate transactions between franchised public utilities that have captive customers or that own or provide transmission service over jurisdictional transmission facilities, and their market-regulated power sales affiliates or non-utility affiliates. The Xcel Energy utility subsidiaries are subject to the new rules. The rules apply historic SEC "at cost" pricing standards to transactions between service companies of utility holding company systems and their FERC jurisdictional public utility affiliates. In September 2008, the National Rural Electric Cooperative Association and the American Public Power Association filed a petition for review of Order No. 707 with the U.S. Court of Appeals for the District of Columbia. The appeal is pending.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement, Division of Investigations (DOI), commenced a non-public investigation of use of network transmission service across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the DOI issued a preliminary report alleging Xcel Energy violated certain FERC policies and rules and approved tariffs. The report represents the preliminary conclusions of the DOI and is subject to additional procedures. The report does not constitute a finding by the FERC, which may accept, modify or reject any or all of the preliminary conclusions set forth in the report. Xcel Energy disagrees with the preliminary report and responded to the DOI allegations. Given the preliminary nature of this matter, Xcel Energy is unable to determine if the resolution of this matter will have a material adverse impact on operations, cash flows or financial condition.

Xcel Energy Electric Operating Statistics

	Year Ended Dec. 31,		
	2008	2007	2006
Electric sales (millions of Kwh)			
Residential	24,448	24,866	24,153
Commercial and industrial	63,511	62,396	61,314
Public authorities and other	1,079	1,087	1,118
Total retail	89,038	88,349	86,585
Sales for resale	23,454	24,202	23,960
Total energy sold	112,492	112,551	110,545
Number of customers at end of period			
Residential	2,891,320	2,859,262	2,831,704
Commercial and industrial	411,935	408,366	403,678
Public authorities and other	71,403	71,726	73,279
Total retail	3,374,658	3,339,354	3,308,661
Wholesale	114	129	138
Total customers	3,374,772	3,339,483	3,308,799
Electric revenues (thousands of dollars)			
Residential	$2,458,105	$2,281,354	$2,149,978
Commercial and industrial	4,625,581	4,099,017	4,014,809
Public authorities and other	127,757	118,024	118,660
Total retail	7,211,443	6,498,395	6,283,447
Wholesale	1,266,256	1,180,728	1,141,248
Other electric revenues	205,294	168,869	183,323
Total electric revenues	$8,682,993	$7,847,992	$7,608,018
Kwh sales per retail customer	26,384	26,457	26,169
Revenue per retail customer	$ 2,137	$ 1,946	$ 1,899
Residential revenue per Kwh	10.05¢	9.17¢	8.90¢
Commercial and industrial revenue per Kwh	7.28	6.57	6.55
Wholesale revenue per Kwh	5.40	4.88	4.76

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 natural gas market prices and the continued trend of declining use per residential customer as a result of improved building construction technologies, higher appliance efficiencies, and conservation. From 1998 to 2008, average annual sales to the typical residential customer declined from 97 MMBtu per year to 83 MMBtu per year on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost recovery mechanisms, the high prices can 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. This law will change to a savings-based requirement beginning in 2010, and the costs of 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 700,323 MMBtu for 2008, which occurred on Dec. 16, 2008.

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 transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 573,668 MMBtu/day. In addition, NSP-Minnesota 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 32 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 2007-2008 and 2008-2009 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:

2008	$8.41
2007	7.67
2006	8.32

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 2009 through 2028.

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, 2008, NSP-Minnesota was committed to approximately $688 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 27 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 Item 7 — Management's Discussion and Analysis.

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 143,216 MMBtu for 2008, which occurred on Jan. 30, 2008.

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 transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 133,546 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 39 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 2008-2009 supply plan was approved by the PSCW in October 2008.

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:

2008	$8.54
2007	7.56
2006	8.42

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 2009 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, 2008, NSP-Wisconsin was committed to approximately $124 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing short-term agreements from approximately 16 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 Item 7 — Management's Discussion and Analysis.

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 and transportation to meet the requirements of its 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 are recovered through the gas DSMCA.

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

***Kinder Morgan Interstate Gas Transmission Bypass Pipeline* —** In August 2007, Kinder Morgan Interstate Gas Transmission LLC (KMIGT) filed an application with the FERC for authorizations to construct and operate 41.4 miles of 12-inch pipeline in Weld County, Colo. The stated purpose of this pipeline, referred to as the "Colorado Lateral," is to provide interstate gas transportation services of up to 55,000 dekatherms per day to supply natural gas to Atmos Energy Corporation's (Atmos) gas distribution system serving retail customers in and around Greeley and Eaton, Colo. PSCo currently provides gas transportation services to Atmos to supply its distribution system in the Greeley and Eaton areas. PSCo's services would be bypassed by the new KMIGT pipeline, resulting in a loss of annual revenues of approximately $3.8 million. In February 2008, the FERC issued its order approving KMIGT's application for the Colorado Lateral project.

PSCo filed a complaint at the CPUC, requesting that the CPUC enter an order finding that Atmos must cease and desist any further construction activity on the Colorado Lateral project that is under the jurisdiction of the CPUC until such time as it applies for and is granted a certificate of public convenience and necessity (CPCN). In September 2008, an ALJ issued an order that the proposed construction of the bypass laterals is not in the normal course of business and ordered Atmos to file a CPCN application for CPUC consideration and approval.

In his recommended decision, the ALJ determined that Atmos' 11-mile section of the "Colorado Lateral" would require Atmos to obtain a CPCN prior to the facilities being placed into service and that the doctrine of regulatory monopoly does not apply to the gas transportation service provided by PSCo, a local distribution company (LDC), to a downstream LDC such as Atmos. Therefore, Atmos has no expectation of service from PSCo and PSCo has no obligation to serve Atmos under the doctrine of regulated monopoly. The CPUC has confirmed the ALJ's ruling in deliberations on Feb. 5, 2009, but has not yet issued a final written order at this time.

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 1,874,731 MMBtu. In addition, firm transportation customers hold 598,660 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,473,391 MMBtu per day. The maximum daily deliveries for PSCo in 2008 for firm and interruptible services were 1,889,099 MMBtu on Dec. 15, 2008.

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 transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,893,712 MMBtu/day, which includes 668,756 MMBtu of supplies held under third-party underground storage agreements. During 2008, an additional 416,419 MMBtu/Day of firm pipeline capacity was added to serve system growth. During this exercise to acquire additional firm pipeline capacity, 165,521 MMBtu of storage capacity was converted to firm transportation with balancing service attached. 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 12-month period 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 previous 12-month period.

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:

2008	$7.04
2007	5.87
2006	7.09

PSCo has 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, 2008, PSCo was committed to approximately $1.5 billion in such obligations under these contracts, which expire in various years from 2009 through 2029.

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 2008, PSCo purchased natural gas from approximately 38 suppliers.

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

Xcel Energy Gas Operating Statistics

	Year Ended Dec. 31,		
	2008	2007	2006
Gas deliveries (thousands of MMBtu)			
Residential	145,615	138,198	126,846
Commercial and industrial	92,682	88,668	81,107
Total retail	238,297	226,866	207,953
Transportation and other	133,207	133,851	135,708
Total deliveries	371,504	360,717	343,661
Number of customers at end of period			
Residential	1,712,835	1,688,994	1,669,747
Commercial and industrial	151,731	149,557	147,614
Total retail	1,864,566	1,838,551	1,817,361
Transportation and other	4,350	4,146	3,981
Total customers	1,868,916	1,842,697	1,821,342
Gas revenues (thousands of dollars)			
Residential	$1,496,772	$1,295,095	$1,330,025
Commercial and industrial	872,224	738,035	755,204
Total retail	2,368,996	2,033,130	2,085,229
Transportation and other	73,992	78,602	70,770
Total gas revenues	$2,442,988	$2,111,732	$2,155,999
MMBtu sales per retail customer	127.80	123.39	114.43
Revenue per retail customer	$ 1,271	$ 1,106	$ 1,147
Residential revenue per MMBtu	10.28	9.37	10.49
Commercial and industrial revenue per MMBtu	9.41	8.32	9.31
Transportation and other revenue per MMBtu	0.56	0.59	0.52

ENVIRONMENTAL MATTERS

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 17 and 18 to the consolidated financial statements and Environmental Matters in Item 7 — Management's Discussion and Analysis.

CAPITAL SPENDING AND FINANCING

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

EMPLOYEES

The number of full-time Xcel Energy employees in continuing operations at Dec. 31, 2008, is presented in the table below. Of the full-time employees listed below, 5,645, or 50 percent, are covered under collective bargaining agreements. See Note 11 in the consolidated financial statements for further discussion of the bargaining agreements.

NSP-Minnesota	3,637
NSP-Wisconsin	546
PSCo	2,772
SPS	1,191
Xcel Energy Services Inc.	3,077
Total	11,223

EXECUTIVE OFFICERS

Richard C. Kelly, 62, 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 Inc., August 2000 to August 2002.

Michael C. Connelly, 47, Vice President and General Counsel, Xcel Energy Inc., June 2007 to present. Previously, Vice President of Human Resources, Xcel Energy Inc., November 2005 to June 2007; Vice President and Deputy General Counsel, Xcel Energy Inc., January 2003 to November 2005 and Deputy General Counsel, Xcel Energy Inc., August 2000 to January 2003.

David L. Eves, 50, 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 Inc., November 2002 to July 2006 and Managing Director, Resource Planning and Acquisition, Xcel Energy Inc., August 2000 to November 2002.

Benjamin G.S. Fowke III, 50, Executive Vice President, Xcel Energy Inc., December 2008 to present; Chief Financial Officer, Xcel Energy Inc., October 2003 to present; Vice President, Xcel Energy Inc., November 2002 to present. Previously, Treasurer, Xcel Energy Inc., October 2003 to May 2004 and Vice President and Chief Financial Officer, Energy Markets Business Unit, Xcel Energy Inc., August 2000 to November 2002.

Raymond E. Gogel, 58, Vice President, Xcel Energy Services Inc., April 2002 to present; Vice President Customer and Enterprise Solutions and Chief Administrative Officer, Xcel Energy Services Inc., 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, 59, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present; Vice President, Corporate Services Group, Xcel Energy Inc., November 2005 to present.

Teresa S. Madden, 52, Vice President and Controller, Xcel Energy Inc., January 2004 to present. Previously, Vice President of Finance, Customer and Field Operations Business Unit, Xcel Energy Inc., 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, 54, President, Director and Chief Executive Officer, NSP-Minnesota, August 2008 to present; Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to August 2008. Previously, Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

Michael L. Swenson, 58, 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, 61, President, Director and Chief Executive Officer, PSCo, September 2007 to present. Previously, Vice President of Asset Management, Utilities Group, Xcel Energy, Inc., February 2006 to September 2007; Vice President, Field Operations, Xcel Energy Inc., January 2004 to February 2006 and Vice President, Asset Management, Xcel Energy Inc., May 2002 to January 2004.

George E. Tyson II, 43, Vice President and Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy Inc., July 2003 to May 2004; Director of Origination, Energy Markets Business Unit, Xcel Energy Inc., May 2002 to July 2003 and Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

David M. Wilks, 62, 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 we operate our utility subsidiaries 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 debt payments and the payment of 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. 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 & 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 & 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, short-term borrowings or incremental long-term debt, which could have an adverse impact on our operating results.

We are subject to capital market risk.

Utility operations require significant capital investment in property, plant 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 and subsequent broad financial market stress, could prevent Xcel Energy from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

We are subject to credit risks.

Credit risk includes the risk that our retail customers will not pay their bills, which may lead to a reduction in liquidity and an eventual increase in bad debt expense. Retail credit risk is comprised of numerous factors including the overall economy and the price of products and services provided.

Credit risk also includes the risk that various 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.

Xcel Energy may at times have direct credit exposure in its short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. Xcel Energy may also have some indirect credit exposure due to participation in organized markets such as the PJM Interconnections and MISO in which any credit losses are socialized to all market participants.

Xcel Energy does have additional indirect credit exposures to various financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party would be in technical default under the contract, which would enable Xcel Energy to exercise its contractual rights.

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, transmission, etc.

We are subject to environmental laws and regulations, with which compliance 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, 2008, these included:

- Sites of former MGPs operated by our subsidiaries, predecessors, or other entities; 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. Likewise, the EPA has issued an Advanced Notice of Proposed Rulemaking that proposes to regulate GHGs under the Clean Air Act. Xcel Energy's electric generating facilities are likely to be subject to regulation under climate change laws 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 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 17 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 its 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. In addition, the Institute for Nuclear Power Operations (INPO) reviews our nuclear operations and nuclear generation facilities. Compliance with INPO recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

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, which are discussed in greater detail in the Capital Markets risk section above.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt. It is expected that commercial and industrial customers will be impacted first with residential customers following, if such circumstances occur. See credit risk section for more related information.

Further, 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, customer response and continuation of the existing utility business model. 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, or any disruption of work force such as may be caused by flu epidemic) 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.

The term business continuity refers to the ability of the firm to maintain day-to-day operations in response to unforeseen events, such as those in the preceding section, which describes numerous disruptions to our normal operating environment. While the immediate response to such events may be part of a pre-existing disaster recovery plan, business continuity is a broader concept that refers to how well the company responds to subsequent pressures on its day-to-day operations. The company's response may have been initially triggered by an event, but when combined with other factors, it has an even greater and longer lasting impact on the firm's on-going business operations.

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. In addition, more than 120 electric reliability standards that were historically subject to voluntary compliance are now mandatory and subject to potential financial penalties by NERC or FERC 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 economic conditions, actual stock market performance, changes in interest rates and any changes in governmental regulations. In addition, the Pension Protection Act of 2006, as amended, 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.

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

We are a holding company and 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, our ability to pay dividends on our common stock and preferred stock or otherwise meet our financial obligations could be adversely affected.

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 2008 Net Dependable Capability (MW)
Steam:			
Sherburne-Becker, MN			
Unit 1	Coal	1976	697
Unit 2	Coal	1977	697
Unit 3	Coal	1987	510[(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	555
Black Dog-Burnsville, MN			
2 Units	Coal/Natural Gas	1955-1960	282
2 Units	Natural Gas	1987-2002	298
Riverside-Minneapolis, MN			
2 Units	Coal	1964-1987	371
Combustion Turbine:			
Angus Anson-Sioux Falls, SD			
3 Units	Natural Gas	1994-2005	384
High Bridge-St. Paul, MN			
3 Units	Natural Gas	2008	566
Inver Hills-Inver Grove Heights, MN			
6 Units	Natural Gas	1972	350
Blue Lake-Shakopee, MN			
6 Units	Natural Gas	1974-2005	490
Various locations			
28 Units	Various	Various	165
Wind:			
Grand Meadow-Mower County, MN		2008	101[(b)]
		Total	7,134

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

(b) Installed December 2008, amount represents nameplate rating capacity.

NSP-Wisconsin

Station, City and Unit	Fuel	Installed	Summer 2008 Net Dependable Capability (MW)
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
Combustion Turbine:			
Flambeau Station-Park Falls, WI	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
Hydro:			
64 Units		Various	257
		Total	872

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

PSCo

Station, City and Unit	Fuel	Installed	Summer 2008 Net Dependable Capability (MW)
Steam:			
Arapahoe-Denver, CO 2 Units	Coal	1951-1955	153
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	238[(b)]
Pawnee-Brush, CO	Coal	1981	505
Valmont-Boulder, CO	Coal	1964	186
Zuni-Denver, CO 2 Units	Natural Gas/Oil	1948-1954	91
Combustion Turbine:			
Fort St. Vrain-Platteville, CO 4 Units 4 Units	Natural Gas	1972-2001	695
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	25[(c)]
Diesel:			
Cherokee-Denver, CO 2 Units	Natural Gas/Oil	1967	6
		Total	3,848

(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.

(c) Amount represents nameplate rating capacity

SPS

Station, City and Unit	Fuel	Installed	Summer 2008 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, 2008:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	5,852	1,153	958	6,800
230 KV	1,801	—	11,420	9,421
161 KV	405	1,393	—	—
138 KV	—	—	92	—
115 KV	6,743	1,529	4,870	10,966
Less than 115 KV	82,448	31,911	72,582	23,087

Electric utility transmission and distribution substations at Dec. 31, 2008:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	372	203	219	432

Natural gas utility mains at Dec. 31, 2008:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	135	—	2,300	12
Distribution	9,506	2,189	21,090	—

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 17 to the consolidated financial statements. For a discussion of proceedings involving utility rates and other regulatory matters, see Item 1 for Public Utility Regulation and Summary of Recent Federal Regulatory Developments, and Item 7 — Management's Discussion and Analysis, and Note 16 to the consolidated financial statements.

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

No issues were submitted for a vote during the fourth quarter of 2008.

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 2008 and 2007 and the dividends declared per share during those quarters.

	High	Low	Dividends
2008			
First quarter	$22.90	$19.39	$0.2300
Second quarter	21.73	19.67	0.2375
Third quarter	22.39	19.40	0.2375
Fourth quarter	20.21	15.32	0.2375
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

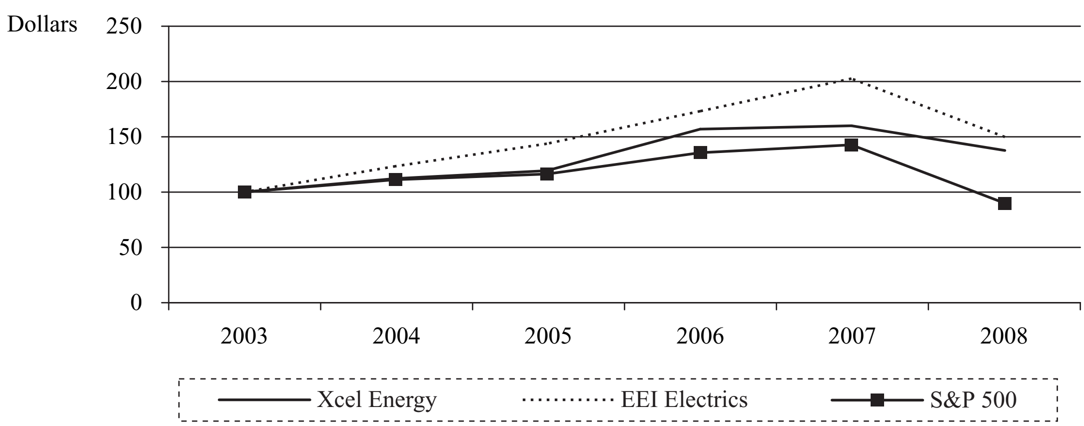
Book value per share at Dec. 31, 2008, was $15.35. The number of common shareholders of record as of Dec. 31, 2008 was approximately 87,000. Xcel Energy's Restated Articles of Incorporation provide for certain restrictions on the payment of cash dividends on common stock.

At Dec. 31, 2008 and 2007, the payment of cash dividends on common stock was not restricted. For further discussion of Xcel Energy's dividend policy, see Item 7 — Management's Discussion and Analysis, Liquidity and Capital Resources.

The following compares our cumulative total shareholder return on common stock with the cumulative total return of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five fiscal years (assuming a $100 investment in each vehicle on Dec. 31, 2003, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 59 companies and is a broad measure of industry performance.

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



* $100 invested on Dec. 31, 2003 in stock and index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2003	2004	2005	2006	2007	2008
Xcel Energy	$100	$112	$119	$156	$159	$137
EEI Investor-Owned Electrics	100	123	143	172	201	149
S&P 500	100	111	116	135	142	90

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

Item 6 — Selected Financial Data

	2008	2007	2006	2005	2004
	(Millions of Dollars, Except Share and Per Share Data)				
Operating revenues	$ 11,203	$ 10,034	$ 9,840	$ 9,625	$ 8,216
Operating expenses	9,812	8,683	8,663	8,533	7,140
Income from continuing operations	646	576	569	499	522
Net income	646	577	572	513	356
Earnings available for common stock	641	573	568	509	352
Average number of common shares outstanding (000's)	437,054	416,139	405,689	402,330	399,456
Average number of common and potentially dilutive shares outstanding (000's)	441,813	433,131	429,605	425,671	423,334
Earnings per share from continuing operations — basic	$ 1.47	$ 1.38	$ 1.39	$ 1.23	$ 1.30
Earnings per share from continuing operations — diluted	1.46	1.35	1.35	1.20	1.26
Earnings per share — basic	1.47	1.38	1.40	1.26	0.88
Earnings per share — diluted	1.46	1.35	1.36	1.23	0.87
Dividends declared per share	0.94	0.91	0.88	0.85	0.81
Total assets	24,958	23,185	21,958	21.505	20,305
Long-term debt[b]	7,732	6,342	6,450	5,898	6,493
Book value per share	15.35	14.70	14.28	13.37	12.99
Return on average common equity	9.7%	9.5%	10.1%	9.6%	6.8%
Ratio of earnings to fixed charges[a]	2.5	2.2	2.2	2.1	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 2008, 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 WYCO, a joint venture formed with a subsidiary of El Paso Corporation to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, 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 4 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, 2008 and Exhibit 99.01 to Xcel Energy's Form 10-K for the year ended Dec. 31, 2008.

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 portfolio of operating utilities. In summary, our objective is to provide value to our customers and execute 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

<u>Overview</u>

Xcel Energy has adopted environmental leadership as a primary focus, forming the cornerstone of our strategic initiatives. Xcel Energy believes that our environmental leadership meets customer and policy maker expectations, while appropriately managing long-term customer costs, and, in turn, creating 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 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 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, establishes environmental performance goals and 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 goals, which include the goal of carbon reduction, are incorporated into officer and employee job responsibilities and compensation.

Current Initiatives

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 assure compliance with state initiatives, appropriately manage long-term customer costs and, where appropriate, provide growth opportunities. These initiatives include the following:

- Xcel Energy is the nation's largest utility wind energy provider and the nation's fifth largest solar 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 RESs in the states in which Xcel Energy operates. These standards provide for favorable cost recovery mechanisms and investment opportunities in order to allow Xcel Energy to meet the requirements.
- 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 allow for a construction work-in-process return and an incentive based ROE mechanism.
- Xcel Energy has announced plans for construction of the largest biomass generating plant in the Midwest. Xcel Energy has proposed installing technology at the Bay Front Generating Station in Ashland, Wis. to allow it to generate electricity from biomass in all three operating units. Xcel Energy currently has 67 MW of biomass generating capacity in Minnesota and Wisconsin.
- Xcel Energy has a number of environmental initiatives focused on our customers. Xcel Energy has the largest customer-driven wind program in the nation called WindSource®. In Colorado, Xcel Energy manages a growing customer-sited solar program, known as Solar*Rewards. Xcel Energy also has an increasing portfolio of customer energy efficiency and conservation programs. Xcel Energy is allowed financial performance incentives associated with our programs in Minnesota and Colorado.
- Xcel Energy is also working to apply intelligence to its electric grid, creating a smart grid, to provide customers with more choice, reliability and control over their energy use. Xcel Energy is building the nation's first fully integrated SmartGridCity™ in Boulder, Colo.
- Xcel Energy is a leader in promoting new clean energy technologies for the future. Pursuant to state statute, NSP-Minnesota manages a renewable development fund derived from customer renewable energy charges in Minnesota that allows it to promote renewable technology advancement. Xcel Energy has recently proposed the creation of an innovative clean technology program in Colorado that creates a funding mechanism to explore innovative renewable and other environmentally sustainable technologies. Xcel Energy has also 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.

Greenhouse Gas Emissions

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. This year, Xcel Energy has adopted a new methodology for calculating CO_2 emissions based on the recently issued reporting protocols of The Climate Registry. (Xcel Energy is a "founding reporter" under The Climate Registry.) Although actual historic emissions from facilities providing power to Xcel Energy customers have not changed, the new accounting methodology has resulted in an increase in Xcel Energy's reported CO_2 intensity and mass emission numbers. To enable accurate comparisons and analysis of emissions trends, Xcel Energy has recalculated historical emissions data to reflect the new accounting methodology. As third-party CO_2 reporting protocols continue to evolve, Xcel Energy expects additional changes in reporting methodology and reported CO_2 emissions.

Based on The Climate Registry's current reporting protocol, Xcel Energy has estimated that its current electric generating portfolio, which includes coal- and gas-fired plants, emitted approximately 66 million tons of CO_2 in 2008. Xcel Energy has also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates that these third-party facilities emitted approximately 21 million tons of CO_2 in 2008. Estimated total CO_2 emissions, associated with service to Xcel Energy electricity customers, declined by 3.2 million tons in 2008 compared to 2007, with a combined cumulative reduction of over 21.9 million tons of CO_2 since 2003. Xcel Energy anticipates that its ownership share of Comanche 3, a new coal-fired generation project scheduled for completion in the fall of 2009, will result in CO_2 emissions of approximately 762,650 tons in 2009. Thereafter, based on Xcel Energy's emissions estimates, 3.4 million tons of CO_2 per year will be attributable to Xcel Energy's ownership share of Comanche 3. Comanche 3, an efficient supercritical pulverized coal unit, will provide low-cost, base load power and help maintain a reliable, reasonably priced and environmentally sound electricity supply in Colorado. Operation of Comanche 3 will help support Xcel energy's efforts to develop renewable energy, retire older, less-efficient resources and take other steps to reduce emissions across its system. Xcel Energy plans to implement aggressive clean resource development and conservation plans that will result in overall reductions in Xcel Energy's CO_2 emissions, both in absolute terms and per Kwh of electricity produced.

State Resource Plans

In 2007, Xcel Energy filed resource plans in Minnesota and Colorado that propose significant new clean energy resources. During 2008, the Colorado plan was approved substantially as proposed, and the Minnesota plan is still under review. Under these plans, Xcel Energy would:

- Increase overall system wind capacity from approximately 2,800 MW at the end of 2008 to approximately 7,400 MW by 2020;
- Add between 200 MW and 600 MW of concentrating solar thermal technology;
- Increase the size of our customer energy efficiency and conservation programs, resulting in a reduction of retail demand;
- Retire and replace several existing coal-fired electric generation facilities;
- Improve the efficiency and reduction of CO_2, mercury, SO_2 and NOx emissions at several existing fossil plants; and
- Upgrade the 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 GHG 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 2008-2009, which was 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 GHG 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, 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. In addition, various jurisdictions have adopted legislation allowing for rider recovery of investments in renewable energy.

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:

- Xcel Energy is making, as part of our MERP program, nearly $1 billion of improvements at three Twin Cities coal-fired generating plants, A. S. King, High Bridge and Riverside, to significantly reduce air emissions from those facilities while increasing the amount of electricity they can produce by approximately 300 MW. New state-of-the-art emission control equipment was placed in service for the A.S. King plant in 2007 and the existing High Bridge facility was replaced with a 575 MW natural gas combined-cycle unit that went into service in May 2008. The final phase of the MERP, the new Riverside combined-cycle plant, is currently scheduled to be placed in service by May 2009.
- Invest approximately $1.3 billion through 2010 for Comanche 3, a project to build a new 750 MW supercritical coal unit in Colorado, scheduled to be completed in late 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.
- Invest approximately $192 million for the planned addition of two gas fired units totaling 300 MW at the Fort St. Vrain generating facility located in Colorado, scheduled to be completed in mid-2009.
- Invest over a $1 billion investment through 2015 to extend the lives and increase the output of our two nuclear facilities, Monticello and Prairie Island.
- Spending approximately $206 million for a new 100 MW wind farm located near Grand Meadows, Minn. The new plant was placed in service in December 2008.
- Invest approximately $900 million over three years for a 201 MW project in southwestern Minnesota called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project, expected to be operational by the end of 2010 and 2011, respectively.
- Investment by the CapX 2020 coalition of utilities of approximately $1.7 billion to expand the transmission system in the upper Midwest with major construction targeted to begin in 2010 and ending three to five years later, of which Xcel Energy's share of the investment is expected to be approximately $900 million, depending on the route and configuration approved by the MPUC.

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 annually, on average, approximately 7 percent from 2008 through 2012.

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

- A long-term 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. However, our operations are affected by current local, national and worldwide economic conditions. The consequences of the current recession being prolonged 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 impact the financial objectives discussed above.

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 us to 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, such as market branding and environmental policy research. From an organizational perspective, examples of similarities include corporate center services as well as certain operational functions, such as management of the generation fleet, 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 and 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.

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.

Discontinued operations consist of the following:

- Quixx Corp., a major portion of which was sold in October 2006;
- UE, 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 4 to the consolidated financial statements for a further discussion of discontinued operations.

	Contribution to Earnings		
	2008	2007	2006
	(Millions of Dollars)		
GAAP income by segment			
Regulated electric utility income — continuing operations	$552.3	$554.7	$503.1
Regulated natural gas utility income — continuing operations	129.3	108.0	70.6
Other regulated utility income[(a)]	27.0	(26.7)	32.3
Total utility income — continuing operations	708.6	636.0	606.0
Holding company costs and other results[(a)]	(62.9)	(60.1)	(37.3)
Total income — continuing operations	645.7	575.9	568.7
Discontinued operations	(0.1)	1.4	3.1
Total GAAP net income	$645.6	$577.3	$571.8

	Contribution to earnings per share		
	2008	2007	2006
GAAP earnings per share contribution by segment			
Regulated electric utility — continuing operations	$1.25	$1.28	$1.17
Regulated natural gas utility — continuing operations	0.29	0.25	0.16
Other regulated utility[(a)]	0.06	(0.06)	0.08
Total utility earnings per share — continuing operations	1.60	1.47	1.41
Holding company costs and other results[(a)]	(0.14)	(0.12)	(0.06)
Total earnings per share — continuing operations	1.46	1.35	1.35
Discontinued operations	—	—	0.01
Total GAAP earnings per share — diluted	$1.46	$1.35	$1.36

(a) Not a reportable segment. Included in All Other segment results in Note 20 to the consolidated financial statements.

Earnings from continuing operations for 2008 were higher than in 2007 primarily attributed to lower operating and maintenance expense, higher electric and gas margins, and higher allowance for funds used during construction — equity. Partially offsetting these positive factors were higher depreciation and amortization, higher conservation and demand-side management program expenses, increased interest expense and a higher effective tax rate.

Earnings from continuing operations for 2007 were higher than in 2006 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.

During 2007, Xcel Energy entered into a settlement agreement with the IRS related to a dispute associated with its COLI program. The following table provides a reconciliation of GAAP earnings and earnings per share to ongoing earnings and earnings per share for the years ended Dec. 31:

	2008	2007	2006
		(Millions of Dollars)	
Ongoing earnings	$641.1	$612.0	$548.2
PSRI/COLI IRS settlement	4.6	(36.1)	20.5
Total continuing operations	645.7	575.9	568.7
Discontinued operations	(0.1)	1.4	3.1
Total GAAP earnings	$645.6	$577.3	$571.8

	2008	2007	2006
Ongoing earnings per share	$1.45	$ 1.43	$1.30
PSRI/COLI IRS settlement	0.01	(0.08)	0.05
Earnings per share — continuing operations	1.46	1.35	1.35
Discontinued operations	—	—	0.01
Total GAAP earnings per share — diluted	$1.46	$ 1.35	$1.36

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.

	2008	2007	2006
Contribution to earnings by company			
NSP-Minnesota	44.3%	45.9%	47.4%
PSCo	52.7	51.0	41.5
SPS	4.9	5.7	8.1
NSP-Wisconsin	7.1	6.5	7.4
Total regulated utility contribution	109.0	109.1	104.4
Holding company and other subsidiaries	(9.0)	(9.1)	(4.4)
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 operating and maintenance expenses. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce operating and maintenance 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 2008 did not impact earnings per share;
- Weather in 2007 increased earnings by an estimated 6 cents per share; and
- Weather in 2006 decreased earnings by an estimated 2 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.

Sales Growth — The following table summarizes Xcel Energy's regulated sales growth for actual and weather-normalized energy sales for the years ended Dec. 31, compared with the previous year. The year-end sales growth amounts for 2008 have been adjusted for leap year.

	2008		2007	
	Actual	Normalized	Actual	Normalized
Electric residential	(2.0)%	0.0%	3.0%	1.9%
Electric commercial and industrial	1.5	2.4	1.8	1.7
Total retail electric sales	0.5	1.7	2.0	1.7
Firm natural gas sales	4.9	1.9	8.6	0.8

During 2008, we experienced flat electric residential sales, primarily driven by a decline in the NSP-Minnesota region. We believe the flat sales growth is a reflection of a recent shift in customer behavior, in part, attributable to the overall economic conditions and conservation efforts. Weather-normalized sales for 2009 are projected to grow between 0.0 percent and 0.5 percent for retail electric utility customers and to decline between (1.0) percent and 0.0 percent for retail natural gas utility customers.

Electric Revenues and Margins

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit 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 margin.

Electric — The following tables detail the electric revenues and margin:

	2008	2007	2006
		(Millions of Dollars)	
Electric revenues	$ 8,683	$ 7,848	$ 7,608
Electric fuel and purchased power	(4,948)	(4,137)	(4,103)
Electric margin	$ 3,735	$ 3,711	$ 3,505

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

Electric Revenues

	2008 vs. 2007
	(Millions of Dollars)
Fuel and purchased power cost recovery	$722
Conservation and non-fuel riders (partially offset in depreciation and amortization expense)	48
Retail rate increases (Wisconsin, North Dakota, Texas interim, New Mexico)	48
Retail sales growth (excluding weather impact)	30
MERP rider	23
Transmission revenues	9
Increased revenues due to leap year (weather normalized impact)	9
Estimated impact of weather	(49)
Revenue subject to refund due to change in nuclear refueling outage recovery method	(18)
Firm wholesale	(10)
Retail customer sales mix	(8)
Other, including fuel recovery	31
Total increase in electric revenues	$835

2008 Comparison with 2007 — Electric revenues increased due to higher fuel and purchased power costs, largely recovered from customers, higher conservation and non-fuel rider recovery, mostly from the RESA rider at PSCO and the RES rider at NSP-Minnesota, electric retail rate increases in Wisconsin, North Dakota, Texas and New Mexico and weather-normalized retail sales growth of approximately 1.7 percent. Unfavorable weather partially offset the positive variances.

	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	26
Miscellaneous revenues (partially offset in operating & maintenance expense)	17
Estimated impact of weather	16
Trading margin	16
Firm wholesale	15
Fuel and purchased power cost recovery	(66)
Other	(6)
Total increase in electric revenues	$240

2007 Comparison with 2006 — Electric 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.

Electric Margin

	2008 vs. 2007
	(Millions of Dollars)
Retail rate increases (Wisconsin, North Dakota, Texas interim and New Mexico)	$ 48
Retail sales growth (excluding weather impact)	30
Conservation and non-fuel riders	28
MERP rider	23
Increased margin due to leap year (weather normalized impact)	9
Estimated impact of weather	(49)
Purchased capacity costs	(30)
Revenue subject to refund due to change in nuclear refueling outage recovery method	(18)
Trading margin	(10)
Retail customer sales mix	(8)
Other, including fuel recovery	1
Total increase in electric margin	$ 24

2008 Comparison to 2007 — The increase in electric margin for the year was due to electric rate increases at Wisconsin, North Dakota, Texas and New Mexico, higher conservation and non-fuel rider revenues and weather-normalized retail sales growth. These items were partially offset by unfavorable weather and higher purchased power costs.

	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 operating & maintenance expense)	18
Estimated impact of weather	16
Transmission revenues, net of expense	15
Conservation and non-fuel riders (partially offset in operating & maintenance expense)	13
Firm wholesale	11
SPS regulatory settlements, including fuel cost recovery	1
Purchased capacity costs	(27)
NSP-Wisconsin fuel cost recovery	(14)
Trading	(13)
Other, including sales mix and other fuel recovery	(4)
Total increase in electric margin	$206

2007 Comparison to 2006 — The increase in 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.

Natural Gas Revenues and Margins

The following table details the changes in natural gas 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.

	2008	2007	2006
		(Millions of Dollars)	
Natural gas revenues	$ 2,443	$ 2,112	$ 2,156
Cost of natural gas sold and transported	(1,833)	(1,548)	(1,645)
Natural gas margin	$ 610	$ 564	$ 511

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

Natural Gas Revenues

	2008 vs. 2007	2007 vs. 2006
	(Millions of Dollars)	
Purchased natural gas cost recovery	$282	$ (128)
Base rate changes	24	21
Estimated impact of weather	10	46
Sales growth (excluding weather impact)	5	2
Conservation revenues	3	2
Revenue due to leap year (weather normalized)	1	—
Transportation	1	6
Other, including late payment fees	5	7
Total increase (decrease) in natural gas revenues	$331	$ (44)

2008 Comparison to 2007 — Natural gas revenues increased primarily due to higher natural gas costs in 2008, which are recovered from customers. Final gas rates were effective for Wisconsin in January 2008 and Minnesota in February 2008. Phase I rates were effective in Colorado since July 2007.

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.

Natural Gas Margin

	2008 vs. 2007	2007 vs. 2006
	(Millions of Dollars)	
Base rate changes — Colorado and Wisconsin	$24	$21
Estimated impact of weather	10	16
Sales growth (excluding weather impact)	5	2
Conservation revenues	3	2
Increased margin due to leap year (weather normalized impact)	1	—
Transportation	(1)	6
Other	4	6
Total increase in natural gas margin	$46	$53

2008 Comparison to 2007 — Natural gas margins increased due to base rate increases for Wisconsin in January 2008 and Phase I rates in Colorado since July 2007.

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.

Non-Fuel Operating Expenses and Other Items

Other Operating and Maintenance Expenses

	2008 vs. 2007
	(Millions of Dollars)
Nuclear outage expenses, net of deferral	$ (13)
Higher allowance for bad debts	7
Lower employee benefit costs	(39)
Higher plant generation costs	9
Higher consulting costs	7
Higher material costs	2
Higher contract labor costs	4
Higher labor costs	22
Other, including nuclear plant operation costs	(10)
Total decrease in other operating and maintenance expenses	$ (11)

2008 Comparison to 2007 — The decrease in operating and maintenance expenses for 2008 was largely driven by the following:

- The decline in nuclear outage expense is due to the MPUC, NDPSC, and SDPUC approving the change in recovery methods for costs associated with refueling outages at Xcel Energy's nuclear plants from the direct expense method to the deferral and amortization method, effective Jan. 1, 2008. An accrual was also recorded to lower revenue, reflecting a liability for a customer refund relating to this decision.
- Lower employee benefit costs are due to eliminating our annual performance based incentive plan payout for 2008.
- The higher plant generation costs were primarily attributable to scheduled and unplanned maintenance.
- The increase in labor costs was attributable to annual wage increases, the in sourcing of certain functions and additional employees to support system growth.

	2007 vs. 2006
	(Millions of Dollars)
Higher combustion/hydro plant costs	$ 33
Higher nuclear plant operation costs	19
Recording of PFS regulatory asset in 2006	17
Higher labor costs	16
Lower gains/losses on sale or disposal of assets, net	10
Higher contract labor 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 allowance for bad debts	(1)
Other, including licenses and permits	5
Total increase in other operating and maintenance expenses	$ 82

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.

Depreciation and Amortization — Depreciation and amortization expense increased by $22.6 million, or 2.8 percent for 2008, compared with 2007. The increase was primarily due to planned system expansion partially offset by a decrease in depreciation due to the MPUC approval of two NSP-Minnesota depreciation filings in September 2008 and a NDPSC settlement agreement in December 2008.

Depreciation and amortization expense increased by $2.8 million, or 0.4 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.

Conservation and Demand Side Management (DSM) — Conservation and DSM expense increased $15.9 million, or 15.7 percent, for 2008, compared with 2007. The higher expense for 2008 is attributable to the expansion of programs and is designed, in part, to meet regulatory commitments. Conservation and DSM program expenses are generally recovered through riders in Xcel Energy's major jurisdictions or through general rate cases.

Allowance for Funds Used During Construction, Equity and Debt (AFDC) — AFDC increased by $30.8 million, or 42.8 percent, for 2008 when compared with 2007. The increase was due primarily to the construction of Comanche 3, which is nearing its final phase and other construction projects.

AFDC increased in total by $16.0 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.

Interest and Other Income, net — Interest and other income increased by $33.0 million, for 2008, compared with 2007. The increase is primarily the result of PSRI's termination of the COLI program in 2007, which eliminated certain expenses.

Interest and other income, net increased $7.0 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 Charges — Interest charges increased by $33 million, or 6.3 percent, for 2008 when compared with 2007. The increase was primarily the result of increased debt levels to fund Xcel Energy's rate base growth strategy.

Interest charges increased by $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.

***Income Taxes* —** Income taxes for continuing operations increased by $44.2 million for 2008, compared with 2007. The increase in income tax expense was primarily due to an increase in pretax income in 2008. The effective tax rate for continuing operations was 34.4 percent for 2008, compared with 33.8 percent for 2007.

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 carryforwards 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 carryforwards. Without these charges and benefits, the effective tax rate for 2007 and 2006 would have been 30.3 percent and 28.2 percent, respectively.

See Note 8 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		
	2008	2007	2006
	(Millions of Dollars)		
Financing costs and preferred dividends — holding company	$(69.7)	$(71.9)	$(66.1)
Eloigne	1.5	2.6	4.6
Holding company, taxes and other results	5.3	9.2	24.2
Total holding company and other loss — continuing operations	$(62.9)	$(60.1)	$(37.3)

	Contribution to Xcel Energy's earnings per share		
	2008	2007	2006
Financing costs and preferred dividends — holding company	$(0.15)	$(0.15)	$(0.12)
Eloigne	—	—	0.01
Holding company, taxes and other results	0.01	0.03	0.05
Total holding company and other loss per share — continuing operations	$(0.14)	$(0.12)	$(0.06)

***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.

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 those listed below.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. Management cannot predict the impact of a prolonged economic recession, 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.

Fuel Supply and Costs

Coal Deliverability — Xcel Energy's operating utilities have varying dependence on coal-fired generation. Coal-fired generation comprises between 56 percent and 79 percent of the total annual generation. Approximately 84 percent of the annual coal requirements are supplied from the Powder River Basin in Wyoming. See additional discussion of fuel supply and costs under Item 1 — Electric Utility Operations.

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 and funding requirements 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, which is affected by overall economic conditions, conservation and DSM efforts and the cost of capital. In addition, the ROE 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. 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. The FERC approved the ASM on December 18, 2008, and MISO began operation of the ASM on Jan. 6, 2009. NSP-Minnesota and NSP-Wisconsin expect to recover MISO charges through either base rates or various recovery mechanisms. See Note 16 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, MPUC and SDPUC approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, and increase 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:

- $213 million in 2008;
- $173 million in 2007; and
- $152 million in 2006.

Xcel Energy expects to expense an average of approximately $245 million per year from 2009 through 2013 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:

- $230 million in 2008;
- $439 million in 2007; and
- $571 million in 2006.

Xcel Energy expects to incur approximately $230 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2009, and approximately $1.4 billion of related expenditures from 2010 through 2013. Included in these amounts are expenditures to reduce emissions of generating plants in Minnesota and Colorado.

See Note 17 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Generating facilities throughout the Xcel Energy territory currently are subject to mercury reduction requirements only at the state level. In Minnesota mercury emissions from A.S. King and Sherco generating facilities will be regulated by the Minnesota Mercury Legislation, and in Colorado, eight units are subject to a mercury emissions rule passed by the Colorado Air Quality Control Commission (AQCC).

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 AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of BART alternatives will cost approximately $254 million in capital costs, which includes approximately $113 million in environmental upgrades for the existing Comanche Station Units 1 and 2 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. Colorado's state implementation plan has been submitted to EPA for approval. In January 2009, the CAPCD initiated a joint stakeholder process to evaluate what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado's Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The stakeholder process will continue throughout 2009.

In January 2008, 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. Given changes in circumstance related to technology, the economy and a lower forecast of energy consumption, NSP-Minnesota is currently reassessing the emissions reduction project at Sherco Units 1 and 2. On Nov. 6, 2008, Xcel Energy filed a request to withdraw the filed plan with the MPUC. The MPUC granted the withdrawal request on Dec. 9, 2008. NSP-Minnesota is reexamining its plans for emission controls at Sherco Units 1 and 2 and anticipates submitting an alternative mercury control plan with the MPUC in 2009.

In October 2008, NSP-Minnesota filed a proposed MERP rider for 2009 designed to recover costs related to MERP environmental improvement projects. Under this rider, NSP-Minnesota proposes to recover $114 million in 2009, an increase of approximately $23 million over 2008.

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, 2008 and 2007, Xcel Energy has recorded regulatory assets of approximately $2.4 billion and $1.1 billion and regulatory liabilities of approximately $1.2 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 19 for additional details on regulatory assets and liabilities.

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 (ETR).

ETRs 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 Accounting Principles Board Opinion No. 28, *Interim Financial Reporting,* 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.

FASB Interpretation No. (FIN) 48, *Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109*, has impacted the income tax accrual process in that this 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 8 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 11 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 and funding requirements are expected to increase in the next few years as a result of significantly lower-than-expected investment returns in 2008. While investment returns exceeded the assumed levels in 2004-2006, investment returns in 2007 and 2008 were below the assumed levels. The investment gains or losses resulting from the difference between the expected pension returns and actual returns earned are deferred in the year the difference arises and are recognized over the expected average remaining years of service for active employees. Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes will increase from an expense of $9.9 million in 2007 and income of $3.0 million in 2008 to expense of $12.3 million in 2009 and $28.4 million in 2010.

Xcel Energy set the discount rate used to value the Dec. 31, 2008 pension and postretirement health care obligations at 6.75 percent, which is a 50 basis point increase from Dec. 31, 2007. Xcel Energy has historically used the Citigroup Pension Liability Index to benchmark the interest rates used in the actuarial calculation. However, as a result of unusual volatility in the index and capital markets during 2008 and especially at year end, Xcel Energy utilized a bond-matching analysis provided by our actuaries to identify a discount rate that more accurately matches the cash flows of Xcel Energy's benefit plans with those of fixed income securities.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Xcel Energy projects cash funding of $70 million to $130 million in 2009 and $150 million to $250 million in 2010. For future years, contributions will be made to avoid benefit restrictions and at-risk status.

These expected contributions are summarized in Note 11 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 Dec. 31, 2008 pension expense determinations, a one-percent change would result in the following impact on the estimates recognized by Xcel Energy:

	Pension Costs	
	+1%	−1%
	(In Millions)	
Rate of Return	$(20.1)	$20.1
Discount Rate	(4.8)	6.9

Effective Dec. 31, 2008, Xcel Energy reduced its initial medical trend assumption from 8.0 percent to 7.4 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is five 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 11 to the consolidated financial statements 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, 2008.

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

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 2067 assuming the prompt dismantlement method. The following key assumptions have a significant effect on these estimates:

- <u>Escalation Rate</u> — 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 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.

- <u>Life Extension</u> — 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 application for the re-licensing of 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. An application to extend the operating licenses for both reactors at Prairie Island by 20 years was submitted to the NRC on April 15, 2008. The NRC is expected to decide on the application in late 2010 or early in 2011.

A new decommissioning study filed with the MPUC in 2008 proposed extension of the final removal date of the Monticello and Prairie Island nuclear plants by 14 and 26 years, respectively, effective Jan. 1, 2009. As a result of the studies for Monticello and Prairie Island nuclear plants, the nuclear production decommissioning ARO and related regulatory asset decreased by $128.5 million and $139.3 million, respectively, in the fourth quarter of 2008.

Revisions to prior estimates were made for asbestos, ash ponds, gas distribution and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

- 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 $1.1 billion and $299.3 million as of Dec. 31, 2008, and $1.3 billion and $39.9 million as of Dec. 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.

See Note 18 for further discussion regarding nuclear decommissioning.

Pending Accounting Changes

Recently Issued

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 apply SFAS No. 141R to business combinations occurring 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 as equity transactions. This statement is effective for fiscal years and interim periods beginning on or after Dec. 15, 2008. Xcel Energy does not expect the implementation of SFAS No. 160 to have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities, an Amendment of FASB Statement No. 133 (SFAS No. 161) — In March 2008, the FASB issued SFAS No. 161, which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for fiscal years and interim periods beginning after Nov. 15, 2008, with early application encouraged. Xcel Energy does not expect the implementation of SFAS No. 161 to have a material impact on its consolidated financial statements.

Employers' Disclosures about Postretirement Benefit Plan Assets (FASB Staff Position (FSP) FAS 132(R)-1) — In December 2008, the FASB issued FSP FAS 132(R)-1, which amends SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits,* to expand an employer's required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 132(R)-1 to have a material impact on its consolidated financial statements.

Recently Adopted

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 was effective for financial statements issued for fiscal years beginning after Nov. 15, 2007.

On Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for all assets and liabilities measured at fair value except for non-financial assets and non-financial liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2, *Effective Date of FASB Statement No. 157*. The adoption did not have a material impact on Xcel Energy's consolidated financial statements. For additional discussion and SFAS No. 157 required disclosures, see Note 15 to the consolidated financial statements.

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 was effective for fiscal years beginning after Nov. 15, 2007. Xcel Energy adopted SFAS No. 159 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active (FSP FAS 157-3) — In October 2008, the FASB issued FSP FAS 157-3, which clarifies the application of SFAS No. 157 in a market that is not active. FSP FAS 157-3 was effective immediately upon issuance, and applied to prior periods for which financial statements had not yet been issued. Xcel Energy adopted FSP FAS 157-3 as of Sept. 30, 2008, and the adoption did not have a material impact on its consolidated financial statements.

***Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements (Emerging Issues Task Force (EITF) Issue No. 06-4)* —** In June 2006, the EITF reached a consensus on EITF No. 06-4, which provides guidance on the recognition of a liability and related compensation costs for endorsement split-dollar life insurance policies that provide a benefit to an employee that extends to postretirement periods. Therefore, this EITF would not apply to a split-dollar life insurance arrangement that provides a specified benefit to an employee that is limited to the employee's active service period with an employer. EITF No. 06-4 was effective for fiscal years beginning after Dec. 15, 2007, with earlier application permitted. Upon adoption of EITF No. 06-4 on Jan. 1, 2008, Xcel Energy recorded a liability of $1.6 million, net of tax, as a reduction of retained earnings. Thereafter, changes in the liability are reflected in operating results.

***Amendment of FASB Interpretation No. 39 (FSP FIN 39-1)* —** In April 2007, the FASB issued FSP FIN 39-1, which amends FIN 39, *Offsetting of Amounts Related to Certain Contracts*, to permit companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 was effective for fiscal years beginning after Nov. 15, 2007. Xcel Energy adopted FSP FIN 39-1 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

***Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11)* —** In June 2007, the EITF reached a consensus on EITF No. 06-11, which states that an entity should recognize a realized tax benefit associated with dividends on nonvested equity shares and nonvested equity share units charged to retained earnings as an increase in additional paid in capital. The amount recognized in additional paid in capital should be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF No. 06-11 was to be applied prospectively to income tax benefits of dividends on equity-classified share-based payment awards that were declared in fiscal years beginning after Dec. 15, 2007. Xcel Energy adopted EITF No. 06-11 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

***The Hierarchy of GAAP (SFAS No. 162)* —** In May 2008, the FASB issued SFAS No. 162, which establishes the GAAP hierarchy, identifying the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements. SFAS No. 162 was effective Nov. 15, 2008. Xcel Energy adopted SFAS No. 162 on Dec. 31, 2008, and the adoption did not have a material impact on its consolidated financial statements.

***Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities (FSP FAS 140-4 and FIN 46(R)-8)* —** In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, which amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* to require public entities to provide additional disclosures about transfers of financial assets. It also amends FIN 46 (revised December 2003), *Consolidation of Variable Interest Entities,* to require public enterprises, including sponsors that have a variable interest in a variable interest entity, to provide additional disclosures about their involvement with variable interest entities. FSP FAS 140-4 and FIN 46(R)-8 was effective for the interim and annual periods ending after Dec. 15, 2008. Xcel Energy adopted FSP FAS 140-4 and FIN 46(R)-8 on Dec. 31, 2008, and the adoption did not have a material impact 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 in Note 13 to the consolidated financial statements.

Xcel Energy is exposed to the impact of changes in price for energy and energy-related products, which is partially mitigated by the company's use of commodity derivatives. Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, the continued turmoil in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Continued distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning trust fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash. Also, the current state of the financial markets may negatively impact Xcel Energy's ability to obtain debt and equity financing under favorable terms.

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, energy and 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, were as follows:

	2008	2007
	(Thousands of Dollars)	
Fair value of commodity trading contract assets (liabilities) outstanding at Jan. 1	$ 6,315	$ (1,175)
Contracts realized or settled during the period	(1,574)	(14,827)
Fair value of commodity trading contract additions and changes during the period	(572)	22,317
Fair value of commodity trading contract assets outstanding at Dec. 31	$ 4,169	$ 6,315

At Dec. 31, 2008, the fair values by source for the commodity trading net asset (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 Value
			(Thousands of Dollars)			
NSP-Minnesota	1	$1,936	$1,133	$ —	$ —	$3,069
	2	91	291	359	158	899
PSCo	1	(804)	—	—	—	(804)
	2	1,358	—	—	—	1,358
Total Futures/Forwards Fair Value		$2,581	$1,424	$359	$158	$4,522

	Options					
	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 Options Fair Value
			(Thousands of Dollars)			
NSP-Minnesota	2	$(353)	$ —	$ —	$ —	$(353)
Total Options Fair Value		$(353)	$ —	$ —	$ —	$(353)

(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.

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, 2008, 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 increase pretax income from continuing operations by approximately $0.2 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 Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

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

	Year ended Dec. 31, 2008	VaR Limit	During 2008 Average	High	Low
			(Millions of Dollars)		
Commodity trading[a]	$0.30	$5.00	$0.30	$1.14	$0.01

	Year ended Dec. 31, 2007	VaR Limit	During 2007 Average	High	Low
			(Millions of Dollars)		
Commodity trading[a]	$0.26	$5.00	$0.47	$1.45	$0.09

[a] Includes transactions for NSP-Minnesota and PSCo.

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, 2008, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $5.6 million. See Note 13 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries' interest rate derivatives.

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, 2008, these funds were invested in a diversified portfolio of taxable and municipal fixed income securities and equity 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 when appropriate, 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. The recent volatility in financial markets could increase our credit risk.

At Dec. 31, 2008, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $1.7 million, while a decrease of 10 percent would have resulted in a decrease of $1.0 million.

Fair Value Measurements

Xcel Energy adopted SFAS No. 157 on Jan. 1, 2008. SFAS No. 157 establishes a hierarchy for inputs used in measuring fair value, and generally requires that the most observable inputs available be used for fair value measurements. Note 15 to the consolidated financial statements describes the SFAS No. 157 fair value hierarchy and discloses the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was immaterial to the fair value of commodity derivative assets at Dec. 31, 2008. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric utility revenues. Credit risk adjustments for short-term wholesale instruments are deferred as regulatory assets and liabilities, reflecting the impact of regulatory recovery.

Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2008.

Commodity derivatives assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long-term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent approximately 3 percent and 26 percent of total assets and liabilities measured at fair value, respectively, at Dec. 31, 2008.

Determining the fair value of a FTR requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation, and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities include $36.9 million and $13.4 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2008.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivatives assets and liabilities include $2.7 million and $2.9 million of estimated fair values, respectively, for commodity forwards and options held at Dec. 31, 2008.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities, however, less observable and subjective risk-based adjustments to estimated yield and forecasted prepayments are often significant to these valuations. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $109.4 million in the nuclear decommissioning fund at Dec. 31, 2008 (approximately 9 percent of total assets measured at fair value), are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

Liquidity and Capital Resources

Cash Flows

	2008	2007[a]	2006
		(Millions of Dollars)	
Cash provided by (used in) operating activities			
Continuing operations	$1,683	$1,560	$1,729
Discontinued operations	(3)	72	195
Total	$1,680	$1,632	$1,924

(a) — See Note 22 to the consolidated financial statements for revision.

Cash provided by operating activities for continuing operations increased by $123 million for 2008 as compared to 2007. The increase is primarily attributable to changes in other current liabilities due to timing for interest payable and accounts payable and an increase in recoverable gas and electric costs. This increase was partially offset by changes in working capital activity due to increased inventory, contributions for pension and non-pension postretirement benefits, and an increase in net regulatory assets and liabilities. The increased inventory reflects the higher cost of natural gas combined with an increase in storage contracts. The increase in net regulatory assets and liabilities reflects the increase in pension funding obligation, and the decrease in fair value of the investments in the decommissioning fund, partially offset by the decrease in the asset retirement obligation for the extended life of the nuclear facilities. Cash provided by operating activities for discontinued operations decreased $75 million, primarily due to decreased income taxes received during 2008.

Cash provided by operating activities for continuing operations decreased by $169 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.

	2008	2007[a]	2006
		(Millions of Dollars)	
Cash (used in) provided by investing activities			
Continuing operations	$(2,156)	$(2,082)	$(1,601)
Discontinued operations	—	—	51
Total	$(2,156)	$(2,082)	$(1,550)

[a] — See Note 22 to the consolidated financial statements for revision.

Cash used in investing activities for continuing operations increased by $74 million during 2008, primarily due to increased capital expenditures, and the continued investment in the WYCO pipeline and storage project. No cash was provided by investing activities for discontinued operations.

Cash used in investing activities for continuing operations increased by $481 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.

	2008	2007	2006
		(Millions of Dollars)	
Cash provided by (used in) financing activities			
Continuing operations	$671	$483	$(422)
Total	$671	$483	$(422)

Cash provided by financing activities related to continuing operations increased by $188 million during 2008 due to the issuance of long-term debt and approximately 17.3 million shares of common stock in the third quarter of 2008. This was partially offset by repayments of short-term borrowings.

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

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 2009 through 2012 are shown in the tables below.

By Segment	2009	2010	2011	2012
Electric	$1,450	$1,970	$2,045	$2,035
Natural gas	170	190	165	180
Common and other	180	140	140	135
Total capital expenditures	1,800	2,300	2,350	2,350
Debt maturities	559	542	52	1,066
Total capital requirements	$2,359	$2,842	$2,402	$3,416

By Subsidiary	2009	2010	2011	2012
NSP-Minnesota	$ 880	$1,340	$1,410	$1,350
NSP-Wisconsin	100	115	135	95
PSCo	610	600	600	710
SPS	210	245	205	195
Total	$1,800	$2,300	$2,350	$2,350

By Project	2009	2010	2011	2012
Base and other capital expenditures	$1,305	$1,500	$1,520	$1,665
Nuclear capacity increases and life extension	130	170	185	150
Comanche 3	130	15	—	—
NSP-Minnesota wind generation	110	420	370	—
CapX 2020	60	100	155	400
MERP	30	10	—	—
Fort St. Vrain	25	—	—	—
Sherco capacity increases	10	20	35	50
Infrastructure investment	—	65	85	85
Total	$1,800	$2,300	$2,350	$2,350

Many of the states in which Xcel Energy operates have enacted RESs, which may require significant increases in investment in renewable generation and transmission. Xcel Energy is 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 potential increased investments for renewable generation and transmission assets.

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 RPSs to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements. See additional discussion in Item 1 — Electric Utility Operations.

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, 2008. See additional discussion in the consolidated statements of capitalization and Notes 5, 6, and 17 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	$16,855,493	$ 1,075,532	$ 1,548,736	$ 2,128,614	$ 12,102,611
Capital lease obligations	79,811	5,984	11,463	10,805	51,559
Operating leases[(a)(b)]	3,221,077	186,360	348,200	326,399	2,360,118
Unconditional purchase obligations	11,456,886	2,410,916	3,003,824	1,756,451	4,285,695
Other long-term obligations — WYCO investment	46,239	35,432	10,807	—	—
Other long-term obligations[(c)]	202,525	31,768	64,362	61,516	44,879
Payments to vendors in process	149,319	149,319	—	—	—
Short-term debt	455,250	455,250	—	—	—
Total contractual cash obligations[(d)(e)(f)]	$32,466,600	$ 4,350,561	$ 4,987,392	$ 4,283,785	$ 18,844,862

(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, 2008, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $162.1 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 $160.3 million, $305.0 million, $292.5 million and $2.3 billion, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories, respectively, pertaining to nine purchase power agreements that were accounted for as operating leases.

(c) Included in other long-term obligations are tax 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 $1.5 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

(f) Xcel Energy expects to have pension funding requirements of $70 million to $130 million in 2009. Pension funding contributions for 2010, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $250 million.

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 utility subsidiaries dividends may be limited indirectly or directly by state regulatory commissions, 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 holding company capitalization ratio at Dec. 31, 2008 and 2007, was 84 percent and 85 percent, respectively. 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 — Xcel Energy uses 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.

General — As a result of recent volatile conditions in global capital markets, general liquidity in short-term credit markets has been periodically constrained. Xcel Energy has maintained access to short-term liquidity through the A2/P2 commercial paper market and utilization of direct borrowing on certain committed credit agreements. In addition, Xcel Energy's overall liquidity was strengthened by the issuance of long-term debt, equity and hybrid securities completed in 2008. The proceeds from these financings were used to refinance maturing debt obligations, to repay short-term debt and to fund general corporate purposes.

Economic Stimulus Plan — On Feb. 17, 2009, President Obama signed into law the federal stimulus bill, which includes investments into many energy industry-related areas. Xcel Energy is reviewing the stimulus package to determine whether federal funding should be used for investments or upgrades to its system. Xcel Energy has had conversations with state utility commissions and state governments in several of the states it serves regarding the stimulus and has identified several areas of interest including renewable energy, energy efficiency, transmission and smart grid technologies. However, Xcel Energy is still debating the merit of applying for such funds. Of particular interest is the smart grid funding because since April 2008, Xcel Energy has been constructing the nation's first large-scale test of such technologies. The project, called SmartGridCity™, is located in Boulder, Colo., and involves distribution system upgrades, installation of a new broadband over power line system, use of in-home automation devices and the potential roll-out of pilot pricing tariffs in fall 2009.

Pension Fund — Xcel Energy's pension costs and funding requirements are projected to increase, as a result of the overall distressed global financial conditions and decline in valuations of both the equity and debt markets. Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, fixed income securities, real estate and alternative investments, including private equity funds and a commodities index. With the recent decline in asset value in Xcel Energy's pension plans, Xcel Energy expects to have 2009 funding requirements of $70 million to $130 million. At this time, pension funding contributions for 2010, which will be dependent on several factors including realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $250 million. The funded status and pension assumptions are summarized in the following tables:

	Dec. 31, 2008	Dec. 31, 2007
	(Millions of dollars)	
Fair value of pension assets	$2,185	$3,186
Projected benefit obligation[(a)]	2,598	2,662
Funded status	$ (413)	$ 524

[(a)] — Excludes non-qualified plan of $46 million and $42 million at Dec. 31, 2008 and 2007, respectively.

Pension Assumptions	2009	2008
Discount rate	6.75%	6.25%
Expected long-term rate of return	8.50	8.75

Short-Term Investments — Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Dec. 31, 2008, approximately $214 million of cash was held in these liquid operating accounts.

The Reserve Primary Fund — On Sept. 17, 2008, NSP-Wisconsin requested redemption of a $40 million principal investment held in The Reserve Primary Fund (the Fund) at $0.97 per share, resulting in a loss of $1.2 million. This request occurred following an announcement by the Fund that the net asset value of the Fund had declined to $0.97 per share following a $785 million write-off of securities issued by Lehman. On Sept. 29, 2008, the Fund issued an announcement that its Board of Trustees had voted to liquidate assets and make a cash distribution to investors in the Fund, including investors who had submitted redemption orders that had not yet been funded.

During the fourth quarter, NSP-Wisconsin received $31.6 million representing its pro-rata share of the Fund's first and second distributions to investors. To date, approximately 80 percent of total fund assets as of the close of business on Sep. 15, 2008, have been returned to investors. NSP-Wisconsin's remaining principal balance due from the Fund (excluding the $1.2 million loss) is approximately $7.3 million.

The Fund has retained all net income generated from its holdings since Sept. 15, 2008. Net income will be distributed in the same manner that excess funds in the special reserve are distributed as outlined in the Fund's Plan of Liquidation and Distribution of Assets under supervision of the SEC.

Nuclear Decommissioning Trust Fund — The recent volatility in global capital markets has lead to a reduction in the current value of long-term investments held in Xcel Energy's nuclear decommissioning trust fund.

The nuclear decommissioning trust fund invests in a diversified portfolio of taxable and municipal fixed income securities and equity securities. The total value of the nuclear decommissioning trust fund was approximately $1.075 billion and $1.318 billion at Dec. 31, 2008, and 2007, respectively. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset or liability on Xcel Energy's consolidated balance sheet.

Commercial Paper — Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy,
- $500 million for NSP-Minnesota,
- $700 million for PSCo and
- $250 million for SPS.

Credit Facilities — As of Feb. 13, 2009 Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

Company	Facility(1)	Drawn(2)	Available	Cash(3)	Liquidity	Maturity
			(Millions of Dollars)			
NSP-Minnesota	$ 482.2	$ 40.8	$ 441.4	$ 44.2	$ 485.6	December 2011
PSCo	675.1	4.9	670.2	0.5	670.7	December 2011
SPS	247.8	10.0	237.8	236.0	473.8	December 2011
Xcel Energy — Holding Company	771.6	454.8	316.8	2.7	319.5	December 2011
NSP-Wisconsin(4)	—	—	—	71.2	71.2	
Total	$2,176.7	$510.5	$1,666.2	$354.6	$2,020.8	

(1) Reflects a reduction in the commitments resulting from the Lehman Brothers bankruptcy, which reduced the credit facilities by $73.3 million, collectively.

(2) Includes direct borrowings, outstanding commercial paper and issued and outstanding letters of credit.

(3) Reflects the payment of common dividends on Jan. 20, 2009.

(4) NSP-Wisconsin does not have a separate credit facility; however, it has a borrowing agreement with NSP-Minnesota.

Listed below is a summary of the banks that make up the credit facilities of Xcel Energy and its subsidiaries as of Feb. 13, 2009.

Bank	Xcel Energy Holding Co.	PSCo	SPS	NSP-Minnesota	Total
			(Millions of Dollars)		
Barclays Bank	$ 54.22	$ 47.44	$ 16.94	$ 33.90	$ 152.50
JP Morgan	54.22	47.44	16.94	33.90	152.50
Bank of America	42.67	37.33	13.33	26.67	120.00
Bank of NY	42.67	37.33	13.33	26.67	120.00
Bank of Tokyo/Mitsubishi	42.67	37.33	13.33	26.67	120.00
BMO Capital Markets	42.67	37.33	13.33	26.67	120.00
BNP Paribas	42.67	37.33	13.33	26.67	120.00
Citibank	42.67	37.33	13.33	26.67	120.00
Key Bank	42.67	37.33	13.33	26.67	120.00
Morgan Stanley Bank	42.67	37.33	13.33	26.67	120.00
Royal Bank of Scotland	42.67	37.33	13.33	26.67	120.00
Scotia Capital	42.67	37.33	13.33	26.67	120.00
UBS	42.67	37.33	13.33	26.67	120.00
Wells Fargo	42.67	37.33	13.33	26.67	120.00
Credit Suisse	28.44	24.89	8.89	17.78	80.00
Goldman Sachs	28.44	24.89	8.89	17.78	80.00
Merrill Lynch	28.44	24.89	8.89	17.78	80.00
Mizuho	28.44	24.89	8.89	17.78	80.00
US Bank	28.44	24.89	8.89	17.78	80.00
Amarillo National Bank	8.89	7.78	2.78	5.55	25.00
Sumitomo	—	—	6.70	—	6.70
Total	$771.57	$675.07	$247.77	$482.29	$2,176.70

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 5 to the consolidated financial statements.

Credit Ratings — 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. 13, 2009, 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	A-	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. A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

On Nov. 5, 2008, S&P increased the senior unsecured credit ratings of NSP-Minnesota, NSP-Wisconsin and PSCo by one notch.

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 14 to the consolidated financial statements. Xcel Energy has no explicit credit rating requirements or hard triggers 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, 2008, and the approved short-term borrowing limits from the money pool are as follows (in millions):

	Borrowings (Loans)	Total Borrowing Limits
Xcel Energy	$(14)	$ —
NSP-Minnesota	64	250
PSCo	41	250
SPS	(91)	100

Registration Statements — Xcel Energy's articles of incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2008, Xcel Energy had approximately 454 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, 2008, 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 $754 million of debt securities.
- NSP-Minnesota has $1.0 billion of debt securities available under its current effective registration statement.
- PSCo has approximately $250 million of debt securities available under its currently effective registration statement. In February 2009, PSCo filed with the SEC to increase the registration statement to $800 million.
- NSP-Wisconsin filed a registration statement in June 2008 that has $50 million remaining under its currently effective registration statement.

Long-Term Borrowings — See a discussion of the long-term borrowings in Note 6 to the consolidated financial statements.

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments through internally generated funds and by periodically issuing short-term debt, long-term debt, common stock, preferred stock and hybrid securities.

Current debt financing plans for 2009 include the following:

- Approximately $400 million of first mortgage bonds at NSP-Minnesota.
- Approximately $400 million of first mortgage bonds at PSCo.

These financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

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 2009 earnings guidance is $1.45 to $1.55 per share. Key assumptions are detailed below:

- Normal weather patterns are experienced for the year.
- Reasonable regulatory outcomes in the Minnesota electric rate case, the Colorado electric rate case, the Texas electric rate case, the New Mexico electric rate case, the SPS FERC wholesale electric rate cases and other rate cases that may be filed during the year.
- Various riders, associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, are expected to increase revenue by approximately $50 million to $60 million over 2008 levels.
- Weather adjusted electric residential sales growth of 0.0 percent to 0.5 percent.
- Weather adjusted retail firm natural gas sales decline by approximately (1.0) percent to 0.0 percent.
- Capacity costs are projected to increase approximately $45 million over 2008 levels. Capacity costs at PSCo are recovered under the purchased capacity cost adjustment.
- Operating and maintenance expenses are projected to increase:
    - Nuclear (including outage amortization) — $55 million
    - Pension and medical — $25 million
    - Other (including incentive compensation) — $75 million — $125 million
- Depreciation and amortization expense is projected to increase approximately $80 million to $90 million over 2008.
- Interest expense increases approximately $20 million to $30 million over 2008 levels.
- Allowance for funds used during construction-equity decreases approximately $5 million to $10 million over 2008.
- An effective tax rate for continuing operations of approximately 33 percent to 35 percent.
- Average common stock and equivalents of approximately 457 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 15-1 in Part IV for index of financial statements included herein.

See Note 21 in the 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, 2008. 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, 2008, 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 herein.

/S/ RICHARD C. KELLY

Richard C. Kelly
Chairman, President and Chief Executive Officer
February 27, 2009

/S/ BENJAMIN G.S. FOWKE III

Benjamin G.S. Fowke III
Executive Vice President and Chief Financial Officer
February 27, 2009

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, 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 8 to the 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2008, 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 27, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 27, 2009

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, 2008, based on criteria established *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, 2008, 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, 2008 of the Company and our report dated February 27, 2009 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 27, 2009

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Income
(amounts in thousands, except per share data)

	Year ended Dec. 31		
	2008	2007	2006
Operating revenues			
Electric	$ 8,682,993	$ 7,847,992	$7,608,018
Natural gas	2,442,988	2,111,732	2,155,999
Other	77,175	74,446	76,287
Total operating revenues	11,203,156	10,034,170	9,840,304
Operating expenses			
Electric fuel and purchased power	4,947,979	4,136,994	4,103,055
Cost of natural gas sold and transported	1,832,699	1,547,622	1,644,716
Cost of sales — other	21,082	24,370	24,388
Other operating and maintenance expenses	1,777,933	1,788,885	1,706,673
Conservation and demand-side management program expenses	117,713	101,772	85,853
Depreciation and amortization	828,379	805,731	802,898
Taxes (other than income taxes)	286,580	277,723	295,727
Total operating expenses	9,812,365	8,683,097	8,663,310
Operating income	1,390,791	1,351,073	1,176,994
Interest and other income, net	43,977	10,948	4,085
Allowance for funds used during construction — equity	63,519	37,207	25,045
Interest charges and financing costs			
Interest charges — includes other financing costs of $20,390, $21,410 and $24,187, respectively	552,919	520,037	486,967
Interest and penalties related to COLI settlement	—	43,401	—
Allowance for funds used during construction — debt	(39,038)	(34,593)	(30,935)
Total interest charges and financing costs	513,881	528,845	456,032
Income from continuing operations before income taxes	984,406	870,383	750,092
Income taxes	338,686	294,484	181,411
Income from continuing operations	645,720	575,899	568,681
Income (loss) from discontinued operations — net of tax	(166)	1,449	3,073
Net income	645,554	577,348	571,754
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available to common shareholders	$ 641,313	$ 573,107	$ 567,513
Weighted average common shares outstanding			
Basic	437,054	416,139	405,689
Diluted	441,813	433,131	429,605
Earnings per share — basic			
Income from continuing operations	$ 1.47	$ 1.38	$ 1.39
Income from discontinued operations	—	—	0.01
Earnings per share	$ 1.47	$ 1.38	$ 1.40
Earnings per share — diluted			
Income from continuing operations	$ 1.46	$ 1.35	$ 1.35
Income from discontinued operations	—	—	0.01
Earnings per share	$ 1.46	$ 1.35	$ 1.36
Cash dividends declared per common share	$ 0.94	$ 0.91	$ 0.88

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Cash Flows
(amounts in thousands of dollars)

	Year ended Dec. 31		
	2008	2007[a]	2006
Operating activities			
Net income	$ 645,554	$ 577,348	$ 571,754
Remove loss (income) from discontinued operations	166	(1,449)	(3,073)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	883,392	855,897	857,129
Nuclear fuel amortization	64,203	53,453	47,531
Deferred income taxes	259,045	265,277	(59,843)
Amortization of investment tax credits	(7,198)	(8,680)	(9,806)
Allowance for equity funds used during construction	(63,519)	(37,207)	(25,045)
Undistributed equity in earnings of unconsolidated affiliates	(3,571)	(1,900)	(2,775)
Allowance for bad debts	63,407	57,434	56,919
Gain or write down of assets sold or held for sale	—	—	(6,189)
Share-based compensation expense	25,511	22,871	40,384
Net realized and unrealized hedging and derivative transactions	(31,895)	6,463	(27,219)
Changes in operating assets and liabilities (net of effects of consolidation of NMC)			
Accounts receivable	(14,108)	(136,807)	119,813
Accrued unbilled revenues	(11,520)	(217,659)	99,716
Inventories	(135,099)	(25,464)	28,967
Recoverable purchased natural gas and electric energy costs	33,947	185,185	136,470
Other current assets	11,937	(9,922)	(1,831)
Accounts payable	28,422	(10,018)	(105,707)
Net regulatory assets and liabilities	(70,993)	27,428	(34,211)
Other current liabilities	48,819	52,771	97,216
Change in other noncurrent assets	54,327	3,265	4,956
Change in other noncurrent liabilities	(97,988)	(99,098)	(56,415)
Operating cash flows (used in) provided by discontinued operations	(3,323)	72,346	195,255
Net cash provided by operating activities	1,679,516	1,631,534	1,923,996
Investing activities			
Utility capital/construction expenditures	(2,112,135)	(2,095,721)	(1,626,000)
Allowance for equity funds used during construction	63,519	37,207	25,045
Purchase of investments in external decommissioning fund	(957,752)	(712,462)	(1,288,103)
Proceeds from the sale of investments in external decommissioning fund	914,514	669,070	1,240,034
Nonregulated capital expenditures and asset acquisitions	(1,111)	(1,136)	(1,620)
Proceeds from sale of assets	—	—	24,670
Investment in WYCO	(97,924)	(29,659)	—
Change in restricted cash	32,008	(9,190)	11,813
Cash obtained from consolidation of NMC	—	38,950	—
Other investments, net	2,564	20,832	13,535
Investing cash flows provided by discontinued operations	—	—	50,516
Net cash used in investing activities	(2,156,317)	(2,082,109)	(1,550,110)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	(633,310)	462,260	(119,820)
Proceeds from issuance of long-term debt	1,915,060	1,162,272	1,326,180
Repayment of long-term debt, including reacquisition premiums	(581,313)	(768,146)	(1,285,584)
Proceeds from issuance of common stock	352,871	10,539	16,275
Dividends paid	(382,282)	(378,892)	(358,746)
Early participation payment on debt exchange	—	(4,859)	—
Net cash (used in) provided by financing activities	671,026	483,174	(421,695)
Net increase (decrease) in cash and cash equivalents	194,225	32,599	(47,809)
Net increase (decrease) in cash and cash equivalents — discontinued operations	3,853	(18,937)	13,071
Cash and cash equivalents at beginning of year	51,120	37,458	72,196
Cash and cash equivalents at end of year	$ 249,198	$ 51,120	$ 37,458
Supplemental disclosure of cash flow information			
Cash paid for interest (net of amounts capitalized)	$ 485,373	$ 469,142	$ 427,683
Cash paid for income taxes (net of refunds received)	94,744	6,467	(13,329)
Supplemental disclosure of non-cash investing transactions:			
Property, plant and equipment additions in accounts payable	$ 55,715	$ 39,681	$ 54,102
Supplemental disclosure of non-cash financing transactions:			
Issuance of common stock for reinvested dividends and 401(k) plans	$ 56,009	$ 53,105	$ 56,194
Issuance of common stock for senior convertible notes	57,500	229,623	—

[a] See Note 22

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

Consolidated Balance Sheets

(amounts in thousands of dollars)

	Dec. 31 2008	Dec. 31 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 249,198	$ 51,120
Accounts receivable, net	900,781	951,580
Accrued unbilled revenues	743,479	731,959
Inventories	666,709	531,610
Recoverable purchased natural gas and electric energy costs	32,843	73,415
Derivative instruments valuation	101,972	94,554
Prepayments and other	263,906	244,134
Current assets held for sale and related to discontinued operations	56,641	128,821
Total current assets	3,015,529	2,807,193
Property, plant and equipment, net	17,688,720	16,675,689
Other assets:		
Nuclear decommissioning fund and other investments	1,232,081	1,372,098
Regulatory assets	2,357,279	1,115,443
Prepaid pension asset	15,612	568,055
Derivative instruments valuation	325,688	383,861
Other	142,130	142,078
Noncurrent assets held for sale and related to discontinued operations	181,456	120,310
Total other assets	4,254,246	3,701,845
Total assets	$24,958,495	$23,184,727
Liabilities and Equity		
Current liabilities:		
Current portion of long-term debt	$ 558,772	$ 637,535
Short-term debt	455,250	1,088,560
Accounts payable	1,120,324	1,079,345
Taxes accrued	220,542	240,443
Accrued interest	168,632	150,490
Dividends payable	108,838	99,681
Derivative instruments valuation	75,539	58,811
Other	331,419	268,720
Current liabilities held for sale and related to discontinued operations	6,929	17,539
Total current liabilities	3,046,245	3,641,124
Deferred credits and other liabilities:		
Deferred income taxes	2,792,560	2,553,526
Deferred investment tax credits	105,716	112,914
Regulatory liabilities	1,194,596	1,389,987
Asset retirement obligations	1,135,182	1,315,144
Derivative instruments valuation	340,802	384,419
Customer advances	323,445	305,239
Pension and employee benefit obligations	1,030,532	576,426
Other	168,352	137,422
Noncurrent liabilities held for sale and related to discontinued operations	20,656	20,384
Total deferred credits and other liabilities	7,111,841	6,795,461
Commitments and contingent liabilities		
Capitalization:		
Long-term debt	7,731,688	6,342,160
Preferred stockholder's equity	104,980	104,980
Common stockholder's equity	6,963,741	6,301,002
Total liabilities and equity	$24,958,495	$23,184,727

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Common Stockholder's Equity and Comprehensive Income
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholder's Equity
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
EITF 06-4 adoption, net of tax of $(1,038)				(1,640)		(1,640)
Net income				645,554		645,554
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $(11,986)					(19,441)	(19,441)
Net derivative instrument fair value changes during the period, net of tax of $(5,758)					(11,697)	(11,697)
Unrealized gain — marketable securities, net of tax of $(513)					(743)	(743)
Comprehensive income for 2008						613,673
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(415,678)		(415,678)
Issuances of common stock	25,009	62,523	372,061			434,584
Share-based compensation			36,041			36,041
Balance at Dec. 31, 2008	453,792	$1,134,480	$4,695,019	$1,187,911	$ (53,669)	$6,963,741

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Consolidated Statements of Capitalization
(amounts in thousands of dollars)

	Dec. 31 2008	Dec. 31 2007
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, 2018, 5.25%	500,000	—
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	350,000
Senior Notes, due Aug. 1, 2009, 6.875%	250,000	250,000
Other	107	31
Unamortized discount	(9,258)	(8,822)
Total	2,962,749	2,463,109
Less current maturities	250,060	31
Total NSP-Minnesota long-term debt	$2,712,689	$2,463,078
PSCo		
First Mortgage Bonds, Series due:		
Oct. 1, 2008, 4.375%	$ —	$ 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
Aug. 1, 2018, 5.8%	300,000	—
Jan. 1, 2019, 5.1%[(b)]	48,750	48,750
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	—
Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000
Capital lease obligations, 11.2% due in installments through 2028	43,423	44,868
Unamortized discount	(5,912)	(5,029)
Total	2,490,761	2,193,089
Less current maturities	201,510	301,445
Total PSCo long-term debt	$2,289,251	$1,891,644
SPS		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ 100,000	$ 100,000
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	—
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
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, 8.5% at Dec. 31, 2008, and 3.43% at Dec. 31, 2007	25,000	25,000
Sept. 1, 2016, 5.75%	57,300	57,300
Unamortized discount	(4,677)	(2,767)
Total	1,022,123	774,033
Less current maturities	100,000	—
Total SPS long-term debt	$ 922,123	$ 774,033

See Notes to Consolidated Financial Statements

Consolidated Statements of Capitalization — (Continued)

(amounts in thousands of dollars)

	Dec. 31 2008	Dec. 31 2007
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
Sept. 1, 2038, 6.375%	200,000	—
Senior Notes due, Oct. 1, 2008, 7.64%	—	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%	726	760
Unamortized discount	(2,233)	(786)
Total	432,093	313,574
Less current maturities	34	80,034
Total NSP-Wisconsin long-term debt	$ 432,059	$ 233,540
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2009-2045, 0% — 9.65%	$ 81,394	$ 86,273
Other	2,062	2,094
Total	83,456	88,367
Less current maturities	7,168	6,116
Total other subsidiaries long-term debt	$ 76,288	$ 82,251
Xcel Energy Inc.		
Unsecured senior notes, Series due:		
July 1, 2008, 3.4%	$ —	$ 195,000
Dec. 1, 2010, 7%	358,636	358,636
April 1, 2017, 5.613%	253,979	253,979
July 1, 2036, 6.5%	300,000	300,000
Jan. 1, 2068, 7.6%	400,000	—
Convertible notes, Series due:		
Nov. 21, 2008, 7.5%	—	57,500
Fair value hedge, carrying value adjustment	—	(2,591)
Unamortized discount	(13,337)	(15,001)
Total	1,299,278	1,147,523
Less current maturities	—	249,909
Total Xcel Energy Inc. long-term debt	$1,299,278	$ 897,614
Total long-term debt	$7,731,688	$6,342,160
Preferred Stockholder's Equity		
Preferred Stock — authorized 7,000,000 shares of $100 par value; outstanding shares: 2008: 1,049,800; 2007: 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 stockholder's equity	$ 104,980	$ 104,980
Common Stockholder's Equity		
Common stock — authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2008: 453,791,770; 2007: 428,782,700	$1,134,480	$1,071,957
Additional paid in capital	4,695,019	4,286,917
Retained earnings	1,187,911	963,916
Accumulated other comprehensive loss	(53,669)	(21,788)
Total common stockholder's equity	$6,963,741	$6,301,002

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements

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 subsidiaries' 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 2008, Xcel Energy continuing operations included the activity of four 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. WGI, an interstate natural gas pipeline company, is also included in continuing regulated utility operations.

Xcel Energy's nonregulated subsidiary in continuing operations is Eloigne, which invests 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 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 4 to the consolidated financial statements.

During 2007, Xcel Energy became the sole remaining partner in NMC. This is the result of the remaining partner leaving NMC during 2007. The exiting company was required to pay an exit fee and surrender its equity interest in NMC. Xcel Energy owns 100 percent of the equity and has a controlling interest in NMC.

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 7 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 presents its revenue net of any excise or other fiduciary-type taxes or fees.

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. 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 in Minnesota and North Dakota also provides a sharing among shareholders and customers of certain margins on short-term wholesale and commodity trading.

- NSP-Wisconsin's rates in Wisconsin 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, or an interim fuel-cost hearing process.
- PSCo generally recovers all prudently incurred electric fuel and purchased energy costs through the ECA for the company's retail jurisdiction. The ECA is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. 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.
- PSCo generally recovers all purchased capacity costs through the PCCA for the company's retail jurisdiction. The PCCA mechanism is revised annually.
- 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, SPS has a monthly fuel and purchased power cost-recovery factor.
- NSP-Minnesota operates under various service quality standards, which could require customer refunds if certain criteria are not met. 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 and certain costs associated with production facilities through rate riders.
- 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 No. 133). In addition, commodity trading results include the impact of all margin-sharing mechanisms. For more information, see Note 13 to the consolidated financial statements.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives, and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value, and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market price curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts, or internally prepared valuation models as primary inputs to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each class of security.

Types of and Accounting for Derivative Instruments — Xcel Energy and its subsidiaries use derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, 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 No. 133, are recorded on the consolidated balance sheets at fair value as derivative instruments valuation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation.

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; vehicle fuel costs are recorded as a component of capital project or operating and maintenance 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 changes in fair value to be recorded within other comprehensive income (OCI), to the extent the hedge is effective, or deferred as a regulatory asset or liability. 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 No. 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 No. 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 hedging 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, or deferred as a regulatory asset or liability 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 hedged transaction and the dollar-offset method is utilized to assess the effectiveness of the actual hedge at inception and on an ongoing basis. Gains and losses related to discontinued hedges that were previously deferred in OCI or deferred as regulatory assets or liabilities will remain deferred until the hedged transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, in which case associated deferred amounts 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 offsets 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 the 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 No. 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 No. 133 as normal purchases or normal sales.

Xcel Energy evaluates all of its contracts at inception to determine if they are derivatives and, if so, if they qualify to meet the normal purchases and normal sales designation requirements under SFAS No. 133. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

For further discussion of Xcel Energy's risk management and derivative activities, see Note 13 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. Regulatory obligations to incur removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. 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 each of the years ended Dec. 31, 2008, 2007 and 2006.

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 is determined based on quoted market prices for those or similar investments. Unrealized gains or losses on the fund's assets are included with regulatory assets on the consolidated balance sheets. For more information on nuclear decommissioning, see Note 18 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.

Nuclear Refueling Outage Costs — Prior to the third quarter of 2008, Xcel Energy expensed the costs associated with refueling outages as incurred at its nuclear plants. In September 2008, the MPUC authorized Xcel Energy to use a deferral and amortization method for the nuclear refueling operating and maintenance costs effective Jan. 1, 2008. This method amortizes refueling outage costs over the period between refueling outages to better match revenues and expenses.

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 SFAS No. 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 book depreciable 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 19 to the consolidated financial statements. For more information on income taxes, see Note 8 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 subsidiaries file consolidated federal income tax returns and 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, 2008 and 2007, Xcel Energy had restricted cash of $1 million and $33 million, respectively. The restricted cash balances primarily represent deposits held in conjunction with short-term wholesale and commodity trading activities. These balances are presented as a component of other 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* (SFAS No. 71). 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 19 to the consolidated financial statements.

Deferred Financing Costs — Other assets included deferred financing costs, net of amortization, of approximately $69 million and $48 million at Dec. 31, 2008 and 2007, 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 paid to settle hedges are amortized over the life of the related debt. The premiums and costs associated with refinanced 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 an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a reserve policy that reflects its expected exposure to the credit risk of customers.

Renewable Energy Credits — RECs are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPSs enacted by those states that are encouraging construction and consumption of renewable energy, but can also be sold separately from the energy produced. Currently, utility subsidiaries acquire 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. RECs 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 expense. 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 accounting 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 — Conservation and DSM program expenses were reclassified as a separate item from both other operating and maintenance expenses and depreciation and amortization on the consolidated statements of income. Activity from the allowance for bad debts was reclassified from the change in accounts receivable on the consolidated statements of cash flows. Accrued interest was reclassified as a separate item rather than as a component of other current liabilities on the consolidated balance sheets. These reclassifications did not have an impact on total operating expenses, net cash provided by operating activities or total current liabilities.

2. Accounting Pronouncements

Recently Issued

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 apply SFAS No. 141R to business combinations occurring 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 as equity transactions. This statement is effective for fiscal years and interim periods beginning on or after Dec. 15, 2008. Xcel Energy does not expect the implementation of SFAS No. 160 to have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities, an Amendment of FASB Statement No. 133 (SFAS No. 161) — In March 2008, the FASB issued SFAS No. 161, which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity's financial position, financial performance and cash flows. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for fiscal years and interim periods beginning after Nov. 15, 2008, with early application encouraged. Xcel Energy does not expect the implementation of SFAS No. 161 to have a material impact on its consolidated financial statements.

Employers' Disclosures about Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) — In December 2008, the FASB issued FSP FAS 132(R)-1, which amends SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits,* to expand an employer's required disclosures about plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 132(R)-1 to have a material impact on its consolidated financial statements.

Recently Adopted

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 was effective for financial statements issued for fiscal years beginning after Nov. 15, 2007.

On Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for all assets and liabilities measured at fair value except for non-financial assets and non-financial liabilities measured at fair value on a non-recurring basis, as permitted by FSP FAS 157-2, *Effective Date of FASB Statement No. 157*. The adoption did not have a material impact on Xcel Energy's consolidated financial statements. For additional discussion and SFAS No. 157 required disclosures, see Note 15 to the consolidated financial statements.

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 was effective for fiscal years beginning after Nov. 15, 2007. Xcel Energy adopted SFAS No. 159 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active (FSP FAS 157-3) — In October 2008, the FASB issued FSP FAS 157-3, which clarifies the application of SFAS No. 157 in a market that is not active. FSP FAS 157-3 was effective immediately upon issuance, and applied to prior periods for which financial statements had not yet been issued. Xcel Energy adopted FSP FAS 157-3 as of Sept. 30, 2008 and the adoption did not have a material impact on its consolidated financial statements.

Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements (Emerging Issues Task Force (EITF) Issue No. 06-4) — In June 2006, the EITF reached a consensus on EITF No. 06-4, which provides guidance on the recognition of a liability and related compensation costs for endorsement split-dollar life insurance policies that provide a benefit to an employee that extends to postretirement periods. Therefore, this EITF would not apply to a split-dollar life insurance arrangement that provides a specified benefit to an employee that is limited to the employee's active service period with an employer. EITF No. 06-4 was effective for fiscal years beginning after Dec. 15, 2007, with earlier application permitted. Upon adoption of EITF No. 06-4 on Jan. 1, 2008, Xcel Energy recorded a liability of $1.6 million, net of tax, as a reduction of retained earnings. Thereafter, changes in the liability are reflected in operating results.

Amendment of FASB Interpretation No. 39 (FSP FIN 39-1) — In April 2007, the FASB issued FSP FIN 39-1, which amends FIN 39, *Offsetting of Amounts Related to Certain Contracts*, to permit companies to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. FSP FIN 39-1 was effective for fiscal years beginning after Nov. 15, 2007. Xcel Energy adopted FSP FIN 39-1 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11) — In June 2007, the EITF reached a consensus on EITF No. 06-11, which states that an entity should recognize a realized tax benefit associated with dividends on nonvested equity shares and nonvested equity share units charged to retained earnings as an increase in additional paid in capital. The amount recognized in additional paid in capital should be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF No. 06-11 was to be applied prospectively to income tax benefits of dividends on equity-classified share-based payment awards that were declared in fiscal years beginning after Dec. 15, 2007. Xcel Energy adopted EITF No. 06-11 on Jan. 1, 2008, and the adoption did not have a material impact on its consolidated financial statements.

The Hierarchy of GAAP (SFAS No. 162) — In May 2008, the FASB issued SFAS No. 162, which establishes the GAAP hierarchy, identifying the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements. SFAS No. 162 was effective Nov. 15, 2008. Xcel Energy adopted SFAS No. 162 on Dec. 31, 2008, and the adoption did not have a material impact on its consolidated financial statements.

Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities (FSP FAS 140-4 and FIN 46(R)-8) — In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, which amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities,* to require public entities to provide additional disclosures about transfers of financial assets. It also amends FIN 46 (revised December 2003), *Consolidation of Variable Interest Entities,* to require public enterprises, including sponsors that have a variable interest in a variable interest entity, to provide additional disclosures about their involvement with variable interest entities. FSP FAS 140-4 and FIN 46(R)-8 was effective for the interim and annual periods ending after Dec. 15, 2008. Xcel Energy adopted FSP FAS 140-4 and FIN 46(R)-8 on Dec. 31, 2008, and the adoption did not have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

	Dec. 31, 2008	Dec. 31, 2007
	(Thousands of Dollars)	
Accounts receivable, net:		
Accounts receivable	$ 965,020	$ 1,000,981
Less allowance for bad debts	(64,239)	(49,401)
	$ 900,781	$ 951,580
Inventories:		
Materials and supplies	$ 158,709	$ 152,770
Fuel	227,462	142,764
Natural gas	280,538	236,076
	$ 666,709	$ 531,610
Property, plant and equipment, net:		
Electric plant	$ 21,601,094	$ 20,313,313
Natural gas plant	3,004,088	2,946,455
Common and other property	1,497,162	1,475,325
Construction work in progress	1,832,022	1,810,664
Total property, plant and equipment	27,934,366	26,545,757
Less accumulated depreciation	(10,501,266)	(10,049,927)
Nuclear fuel	1,611,193	1,471,229
Less accumulated amortization	(1,355,573)	(1,291,370)
	$ 17,688,720	$ 16,675,689

4. Discontinued Operations

Xcel Energy classified and accounted for certain assets as held for sale at Dec. 31, 2008 and 2007. 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 2008 and 2007 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.

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

	2008	2007
	(Thousands of Dollars)	
Cash	$ 10,645	$ 6,792
Account receivables, net	209	913
Deferred income tax benefits	39,422	118,919
Other current assets	6,365	2,197
Current assets held for sale and related to discontinued operations	56,641	128,821
Deferred income tax benefits	150,912	97,284
Other noncurrent assets	30,544	23,026
Noncurrent assets held for sale and related to discontinued operations	181,456	120,310
Accounts payable	760	1,060
Other current liabilities	6,169	16,479
Current liabilities held for sale and related to discontinued operations	6,929	17,539
Other noncurrent liabilities	20,656	20,384
Noncurrent liabilities held for sale and related to discontinued operations	$ 20,656	$ 20,384

5. Short-Term Borrowings and Other Financing Instruments

Commercial Paper — At Dec. 31, 2008 and 2007, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $330.3 and $1.1 billion, respectively. The weighted average interest rates at Dec. 31, 2008 and 2007 were 3.53 percent and 5.57 percent, respectively. At Dec. 31, 2008 and 2007, Xcel Energy and its utility subsidiaries had combined board approval to issue up to $2.25 billion of commercial paper.

Credit Facility Bank Borrowings — At Dec. 31, 2008, Xcel Energy and its utility subsidiaries had credit facility bank borrowings of $125.0 million with a weighted average interest rate of 1.88 percent. Xcel Energy and its utility subsidiaries had no credit facility bank borrowings at Dec. 31, 2007.

Money Pool — Xcel Energy and its utility subsidiaries have established a utility money pool arrangement that 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. At Dec. 31, 2008 and 2007, Xcel Energy and its utility subsidiaries had money pool loans outstanding of $104.5 million and $100.6 million, respectively. The weighted average interest rates at Dec. 31, 2008 and 2007 were 3.48 percent and 5.64 percent, respectively.

6. Long-Term Borrowings and Other Financing Instruments

Credit Facilities — At Dec. 31, 2008, Xcel Energy and its utility subsidiaries had the following committed credit facilities available:

	Credit Facility[1]	Credit Facility Borrowings	Available[2]	Original Term	Maturity
	(Millions of Dollars)				
NSP-Minnesota	$ 482.2	$ —	$ 411.4	Five year	December 2011
PSCo	675.1	—	630.2	Five year	December 2011
SPS	247.8	—	236.2	Five year	December 2011
Xcel Energy — holding company	771.6	125.0	420.7	Five year	December 2011
Total	$2,176.7	$125.0	$1,698.5		

(1) Reflects a reduction in the commitments resulting from the Lehman Brothers bankruptcy, which reduced the credit facilities by $73.3 million, collectively.

(2) 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, 2008 and 2007. 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.
- The commitment fees, also based on applicable debt ratings, are calculated on the unused portion of the lines of credit at 8 annual basis points for Xcel Energy, PSCo and SPS, and at 6 annual basis points for NSP-Minnesota.

Xcel Energy and its utility subsidiaries have $2.2 billion in senior unsecured revolving credit facilities that mature in December 2011. Xcel Energy and its utility subsidiaries have 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, 2008, Xcel Energy had short-term borrowings of $125.0 million on this line of credit. In addition, the credit facilities were used to provide backup for $330.3 million of commercial paper outstanding and $23.0 million of letters of credit.

- At Dec. 31, 2007, Xcel Energy and its utility subsidiaries had no direct borrowings on these lines of credit; however, the credit facilities were used to provide backup for $1.1 billion of commercial paper outstanding and $19.0 million of letters of credit.

Long-Term Borrowings

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)
2009	$ 558.8
2010	541.6
2011	51.5
2012	1,066.4
2013	256.1

Xcel Energy

On Jan. 16, 2008, Xcel Energy issued $400 million of 7.6 percent junior subordinated notes (Junior Notes) due 2068. Due to certain features, rating agencies consider the Junior Notes to be hybrid debt instruments with a combination of debt and equity characteristics. The Junior Notes are not redeemable by Xcel Energy prior to 2013 without payment of a make-whole premium. The proceeds from this offering were used to repay short-term debt.

Interest payments on the Junior Notes may be deferred on one or more occasions for up to 10 consecutive years. If the interest payments on the Junior Notes are deferred, Xcel Energy may not declare or pay any dividends or distributions, or redeem, purchase, acquire, or make a liquidation payment on, any shares of its capital stock. Also during the deferral period, Xcel Energy may not make any principal or interest payments on, or repay, purchase or redeem any of its debt securities that are equal in right of payment with, or subordinated to, the Junior Notes. Xcel Energy also may not make payments on any guarantees equal in right of payment with, or subordinated to, the Junior Notes.

In connection with the completion of this offering, Xcel Energy entered into a Replacement Capital Covenant (RCC) for the benefit of persons that buy, hold, or sell a specified series of Xcel Energy long-term indebtedness ranking senior to the Junior Notes. Initially, Xcel Energy's 6.50 percent Senior Notes due July 1, 2036, was specified as such series of long-term debt. Under the terms of the RCC, Xcel Energy agrees not to redeem or repurchase all or part of the Junior Notes prior to 2038 unless qualifying securities are issued to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Notes at the time of redemption or repurchase.

NSP-Minnesota

On March 18, 2008, NSP-Minnesota issued $500 million of 5.25 percent first mortgage bonds, series due March 1, 2018. 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 and borrowings under the utility money pool arrangement.

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 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.

NSP-Wisconsin

On Jan. 14, 2009, NSP-Wisconsin announced a tender for and repurchase of any and all principal amount and accrued interest of the remaining 7.375 percent $65 million first mortgage bonds due Dec. 1, 2026 with the tender period running through March 1, 2009. The net costs are anticipated to be $3.0 million related to this repayment of debt and will be recorded in the first quarter of 2009. The debt repayment will be funded by existing cash resources.

On Sept. 10, 2008, NSP-Wisconsin issued $200 million of 6.375 percent first mortgage bonds, series due Sept. 1, 2038. NSP-Wisconsin added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $80 million of 7.64 percent senior notes due Oct. 1, 2008. The balance of the net proceeds was used for the repayment of short-term debt (including notes payable to affiliates) and for general corporate purposes.

PSCo

On Aug. 13, 2008, PSCo issued $300 million of 5.80 percent first mortgage bonds, series due Aug. 1, 2018 and $300 million of 6.50 percent first mortgage bonds, series due Aug. 1, 2038. PSCo added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $300 million of 4.375 percent first mortgage bonds due Oct. 1, 2008.

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.

SPS

On Nov. 14, 2008, SPS issued $250 million of 8.75 percent senior notes, series due 2018. The senior notes are redeemable by SPS upon 30 days notice with payment of a make-whole premium. The proceeds from this offering were used to repay short-term debt.

Convertible Senior Notes

Xcel Energy's 2007 and 2008 series convertible senior notes included provisions for conversion into shares of Xcel Energy common stock at a conversion price of $12.33 per share. Conversion was at the option of the holder at any time prior to maturity. In addition, Xcel Energy was required to 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 exceeded 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 21, 2008, the Board of Directors of Xcel Energy voted to raise the quarterly dividend on its common stock from 23.00 cents per share to 23.75 cents per share. Consequently, as of Dec. 31, 2008 and 2007, a total of $0.7 million and $2.1 million in additional interest expense has been recorded, respectively. During the fourth quarter of 2008, $57.5 million of remaining Xcel convertible notes due Nov. 21, 2008, were converted to common stock. During the second and fourth quarter of 2007, approximately $126 million and $104 million, respectively, of Xcel convertible notes due Nov. 21, 2007, were converted to common stock.

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 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 EITF No. 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 No. 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.

7. 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, 2008:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
	(Thousands of Dollars)			
NSP-Minnesota				
Sherco Unit 3	$527,647	$325,472	$ 128	59.0
Sherco Common Facilities Units 1, 2 and 3	122,812	73,779	180	75.0
Transmission facilities, including substations	4,790	2,231	—	59.0
Total NSP-Minnesota	$655,249	$401,482	$ 308	

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
PSCo				
Hayden Unit 1	$ 88,386	$ 54,319	$ 411	75.5
Hayden Unit 2	81,504	51,680	2,047	37.4
Hayden Common Facilities	31,563	11,479	414	53.1
Craig Units 1 and 2	53,421	31,334	358	9.7
Craig Common Facilities Units 1, 2 and 3	33,205	14,058	456	6.5-9.7
Comanche Unit 3	—	—	672,144	66.7
Transmission and other facilities, including substations	141,119	52,803	529	11.6-68.1
Total PSCo	$429,198	$215,673	$676,359	

NSP-Minnesota is part owner of Sherco unit 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 construction and operating costs.

PSCo's current operational assets include approximately 320 MW 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, NSP-Minnesota 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 included in NSP-Minnesota'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 NSP-Minnesota for the year ended Dec. 31,

2007. NSP-Minnesota has reintegrated its nuclear operations into its generation operations. The NRC transferred the nuclear operating licenses from NMC to NSP-Minnesota effective Sept. 22, 2008.

8. 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 files a consolidated federal income tax return and 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.

In the first quarter of 2008, the IRS completed an examination of Xcel Energy's federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. Tax year 2004 is the earliest open year and the statute of limitations applicable to Xcel Energy's 2004 federal income tax return remains open until Dec. 31, 2009. In the third quarter of 2008, the IRS commenced an examination of tax years 2006 and 2007. As of Dec. 31, 2008, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

In the first quarter of 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an income tax audit through tax year 2005. No material adjustments were proposed for these state audits. As of Dec. 31, 2008, 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-2004, Minnesota-2004, Texas-2004, Wisconsin-2004. There currently are no state income tax audits in progress.

The amount of unrecognized tax benefits reported in continuing operations was $26.3 million on Dec. 31, 2007 and $35.5 million on Dec. 31, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $4.3 million on Dec. 31, 2007 and $6.6 million on Dec. 31, 2008. A reconciliation of the beginning and ending amount of unrecognized tax benefit in continuing operations is as follows:

	2008	2007
	(Millions of Dollars)	
Balance at Jan. 1	$ 26.3	$ 42.6
Additions based on tax positions related to the current year	9.7	10.4
Reductions based on tax positions related to the current year	(1.0)	(0.4)
Additions for tax positions of prior years	7.6	42.3
Reductions for tax positions of prior years	(0.3)	(5.0)
Settlements with taxing authorities	(4.0)	(63.6)
Lapse of applicable statute of limitations	(2.8)	—
Balance at Dec. 31	$ 35.5	$ 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 $7.8 million on Dec. 31, 2007 and $13.1 million on Dec. 31, 2008 and net operating loss and tax credit carryovers reported in discontinued operations of $17.8 million on Dec. 31, 2007 and $26.5 million on Dec. 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $9.8 million and $9.2 million of tax positions on Dec. 31, 2007 and 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $16.5 million and $26.3 million of tax positions on Dec. 31, 2007 and 2008, 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 increase in the unrecognized tax benefit balance reported in continuing operations of $9.2 million from Dec. 31, 2007 to Dec. 31, 2008, was due to the addition of similar uncertain tax positions related to ongoing activity, partially offset by a decrease due to the expiration of statutes of limitations. Xcel Energy's amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the IRS audit of 2006 and 2007 progresses and when state audits resume. 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.

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 amount of interest income related to unrecognized tax benefits reported within interest charges in continuing operations in 2008 was $3.9 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $5.8 million and $1.9 million on Dec. 31, 2007 and 2008, respectively. The amount of interest expense related to unrecognized tax benefits reported within interest charges in discontinued operations in 2007 was $1.6 million. The amount of interest income related to unrecognized tax benefits reported within interest charges in discontinued operations in 2008 was $1.0 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $0.5 million and $1.5 million on Dec. 31, 2007 and 2008, respectively.

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. In 2008, the liability for penalties related to unrecognized tax benefits was reversed and a $1.0 million benefit was reported within interest charges in continuing operations in 2008. No amounts were accrued for penalties as of Dec. 31, 2008.

Other Income Tax Matters — Xcel Energy's federal net operating loss and tax credit carryforwards are estimated to be $127 million and $223 million, respectively, as of Dec. 31, 2008, and $459 million and $140 million, respectively, as of Dec. 31, 2007. A portion of the net operating loss and tax credit carryforwards in the amount of $49 million and $126 million, respectively, as of Dec. 31, 2008 and $282 million and $51 million, respectively, as of Dec. 31, 2007, are included in discontinued operations. The carryforward periods expire between 2021 and 2028. Xcel Energy also has state net operating loss and tax credit carryforwards of $1.1 billion and $17 million, respectively, as of Dec. 31, 2008 and $1.4 billion and $15 million, respectively, as of Dec. 31, 2007. A portion of the state net operating loss and tax credit carryforwards in the amount of $980 million and $2 million, respectively, as of Dec. 31, 2008 and $1.3 billion and $1 million, respectively, as of Dec. 31. 2007 are included in discontinued operations. The state carryforward periods expire between 2009 and 2027. Xcel Energy has a valuation allowance for its state net operating loss carryforward in the amount of $37 million and $16 million as of Dec. 31, 2008 and Dec. 31, 2007, respectively, primarily reported in discontinued operations.

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:

	2008	2007	2006
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.4	4.5	3.0
Life insurance policies	(0.2)	(3.7)	(4.6)
Tax credits recognized, net of federal income tax expense	(1.8)	(2.5)	(3.2)
Capital loss carry forward utilization	—	—	(2.6)
Resolution of income tax audits and other	—	(0.7)	(1.5)
Regulatory differences — utility plant items	(2.1)	(1.1)	(0.5)
FIN 48 expense — unrecognized tax benefits	(0.1)	3.1	—
Other, net	(0.8)	(0.8)	(1.4)
Effective income tax rate from continuing operations	34.4%	33.8%	24.2%

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

	2008	2007	2006
	(Thousands of Dollars)		
Current federal tax expense	$ 56,044	$ 10,649	$209,941
Current state tax expense	26,904	6,726	41,119
Current FIN 48 tax expense	3,891	20,512	—
Deferred federal tax expense (benefit)	236,307	225,971	(35,795)
Deferred state tax expense (benefit)	38,758	47,555	(8,503)
Deferred FIN 48 tax (benefit) expense	(4,535)	6,926	—
Deferred tax credits	(11,485)	(15,175)	(15,545)
Deferred investment tax credits	(7,198)	(8,680)	(9,806)
Total income tax expense from continuing operations	$338,686	$294,484	$181,411

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

	2008	2007
	(Thousands of Dollars)	
Deferred tax liabilities:		
Differences between book and tax bases of property	$2,770,768	$2,535,181
Regulatory assets	188,603	168,080
Employee benefits	40,708	16,707
Deferred costs	49,195	101,287
Other	57,126	30,507
Total deferred tax liabilities	$3,106,400	$2,851,762
Deferred tax assets:		
Net operating loss carry forward	$ 46,297	$ 77,350
Tax credit carry forward	112,952	103,585
Unbilled revenues	83,128	73,852
Other comprehensive income	37,032	19,794
Deferred investment tax credits	41,460	44,220
Rate refund	40,347	23,767
Regulatory liabilities	32,444	32,608
Environmental remediation	28,443	18,438
Bad debts	25,136	19,299
Accrued liabilities and other	18,177	8,574
Total deferred tax assets	$ 465,416	$ 421,487
Net deferred tax liability	$2,640,984	$2,430,275

9. 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, 2008 and 2007, Xcel Energy had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102 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, 2008 and 2007, there are no preferred shares of subsidiaries outstanding. The following table lists preferred shares by subsidiary:

	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 — On Sept. 15, 2008, Xcel Energy issued 15,000,000 shares of common stock to underwriters at a price of $20.10 per share. The shares were re-offered to the public at a price of $20.20 per share plus a commission of $0.05 per share from the purchasers. On Sept. 18, 2008, Xcel Energy issued 2,250,000 shares of common stock pursuant to the underwriters' exercise in full of their over-allotment. The proceeds from these offerings were used to repay commercial paper.

Xcel Energy has common stock equivalents consisting of convertible senior notes, 401(k) equity awards and stock options. 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 2008, 2007 and 2006, Xcel Energy had approximately 8.1 million, 8.5 million and 11.0 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:

	2008			2007			2006		
	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	$645,720			$575,899			$568,681		
Less: Dividend requirements on preferred stock	(4,241)			(4,241)			(4,241)		
Basic earnings per share									
Earnings available to common shareholders	641,479	437,054	$1.47	571,658	416,139	$1.38	564,440	405,689	$1.39
Effect of dilutive securities:									
Convertible senior notes	4,498	4,144		10,411	16,425		15,112	23,317	
401(k) equity awards	—	596		—	482		—	551	
Stock options	—	19		—	85		—	48	
Diluted earnings per share									
Earnings available to common shareholders and assumed conversions	$645,977	441,813	$1.46	$582,069	433,131	$1.35	$579,552	429,605	$1.35

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 2008, 2007 and 2006 are:

Dividends Per Share	2008	2007	2006
First quarter	$0.2300	$0.2225	$0.2150
Second quarter	0.2375	0.2300	0.2225
Third quarter	0.2375	0.2300	0.2225
Fourth quarter	0.2375	0.2300	0.2225
	$0.9425	$0.9125	$0.8825

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, 2008 and 2007, was 84 percent and 85 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 $999 million and $946 million in additional cash dividends on common stock at Dec. 31, 2008 and 2007, 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 $250 million of long-term debt and up to $800 million of short-term debt at any one time outstanding. PSCo has filed an application with the CPUC to increase the long-term debt authorization to $800 million.
- SPS currently has authorization to issue up to $400 million in short-term debt.
- NSP-Wisconsin currently has authorization to issue up to $250 million of long-term debt and $100 million of short-term debt.
- NSP-Minnesota has authorization to issue long-term securities provided the equity ratio remain between 46.26 percent and 56.54 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $7.5 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. The utility subsidiaries participate in the money pool, in amounts ranging from $250 million for each of NSP-Minnesota and PSCo, to $100 million for SPS and $100 million for NSP-Wisconsin to borrow only from NSP-Minnesota. NSP-Wisconsin is not authorized and does not participate in the money pool.

Stockholder Protection Rights Agreement — In June 2001, Xcel Energy adopted a Stockholder Protection Rights Agreement (Rights Agreement) pursuant to which each share of Xcel Energy's common stock included one shareholder protection right. On Dec. 11, 2008, Xcel Energy amended the Rights Agreement, changing the expiration date of the agreement from June 28, 2011 to Dec. 11, 2008. Accordingly, the Rights Agreement expired on Dec. 11, 2008, and all associated rights have expired.

10. Share-Based Compensation

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 diluted 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:

	2008		2007		2006	
	Awards	Average Exercise Price	Awards	Average Exercise Price	Awards	Average Exercise Price
			(Awards in thousands)			
Outstanding beginning of year	9,547	$27.19	12,374	$27.36	13,576	$26.92
Exercised	(12)	18.28	(266)	19.18	(563)	18.33
Forfeited	(67)	22.28	(50)	27.43	(89)	26.98
Expired	(1,008)	28.76	(2,511)	29.37	(550)	25.66
Outstanding at end of year	8,460	27.05	9,547	27.19	12,374	27.36
Exercisable at end of year	8,460	27.05	9,547	27.19	12,374	27.36

	Range of Exercise Prices		
	$18.94 to $26.00	$26.01 to $30.00	$30.01 to $51.25
Options outstanding and exercisable:			
Number outstanding and exercisable	2,832,105	5,104,485	523,083
Weighted average remaining contractual life (years)	2.2	1.6	2.5
Weighted average exercise price	$ 23.73	$ 26.90	$ 46.50

The total market value of stock options exercised and the total intrinsic value of options exercised were as follows for the years ended Dec. 31:

	2008	2007	2006
		(Thousands of Dollars)	
Market value of exercises	$250	$6,398	$12,108
Intrinsic value of options exercised[(a)]	36	1,293	1,795

(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 and settles 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 fair value equal to the market trading price of Xcel Energy's stock at the grant date. Xcel Energy granted shares of restricted stock for the years ended Dec. 31 as follows:

	2008	2007	2006
Granted shares	27,931	37,000	10,481
Grant date fair value	$ 20.62	$ 24.27	$ 19.10

A summary of the status of nonvested restricted stock as of Dec. 31, 2008, and changes for the year then ended, are as follows:

	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1, 2008	48,154	$23.13
Granted	27,931	20.62
Vested	(19,915)	22.17
Dividend equivalents	2,676	19.54
Nonvested restricted stock at Dec. 31, 2008	58,846	22.06

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 attachment of various performance goals to 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 through 2008 will not lapse, under any circumstances, even if performance goals have been achieved, until two years after the grant date.

Other than for the 2004 grants discussed further below, for which restrictions lapse upon meeting a total shareholder return (TSR) goal, payout of the restricted stock 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 for grant years prior to 2008). Additionally, Xcel Energy's annual dividend paid on its common stock must remain at a specified amount 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 results of environmental performance targets measured as a percentage of target performance meets or exceeds threshold performance. The environmental performance indicators will be measured annually at the end of each fiscal year. For all units, if the performance criteria have not been met within four years of the date of grant, all associated units shall be forfeited.

In January 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 TSR for this grant was $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.

The 2005 environmental restricted stock units met their target as of Dec. 31, 2006 and were settled in shares in February 2007. In addition, the 2005 restricted stock units measured on EPS growth and all 2006 restricted stock units met their targets as of Dec. 31, 2007 and were settled in shares in February 2008.

The restricted stock units granted for the years ended Dec. 31 were as follows:

	2008	2007	2006
		(Units in Thousands)	
Units granted	460	313	390
Grant date fair value	$20.60	$19.08	$15.13

A summary of the status of nonvested restricted stock units as of Dec. 31, 2008, and changes for the year then ended, are as follows:

	Units	Weighted Average Grant Date Fair Value
	(Units in Thousands)	
Nonvested restricted stock units at Jan. 1, 2008	299	$19.08
Granted	460	20.60
Forfeited	(71)	19.80
Dividend equivalents	27	20.08
Nonvested restricted stock units at Dec. 31, 2008	715	20.03

The total fair value of nonvested restricted stock units as of Dec. 31, 2008 was $13.3 million and the weighted average remaining contractual life was 2.6 years.

No restricted stock units vested during the year ended Dec. 31, 2008. The total fair value of restricted stock units vested during the years ended Dec. 31, 2007 and 2006 was $14.2 million and $10.6 million, respectively.

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 attach various performance goals to the performance share awards granted. The PSP has been historically dependent on a single measure of performance, Xcel Energy's TSR measured over a three-year period. Xcel Energy's TSR is compared to the TSR of other companies in the EEI Investor-Owned 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.

In January 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 cash and shares of common stock in February 2007.

In January 2005, Xcel Energy granted 323,889 performance share awards under the Xcel Energy Omnibus Incentive Plan, which had a grant date fair value of $18.10. These performance share awards met the TSR requirements as of Dec. 31, 2007 and were settled in cash and shares of common stock in February 2008.

The PSP awards granted for the years ended Dec. 31 were as follows:

	2008	2007	2006
		(Awards in thousands)	
Share awards granted	216	231	262
Vesting period (in years)	3	3	3

The 2006, 2007 and 2008 awards were granted under the Xcel Energy 2005 Omnibus Incentive Plan.

The total settlement amounts of performance awards settled during the years ended Dec. 31 were as follows:

	2008	2007	2006
		(In Thousands)	
Share awards settled	328	395	1,139
Settlement amount (cash and common stock)	$6,826	$9,613	$21,756

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. 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. Restricted stock as granted under the Xcel Energy Executive Annual Incentive Award Plan is also considered to be an equity award. The grant date fair value of restricted stock units and restricted stock is expensed as employees vest in their rights to those awards.

The PSP 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 liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, 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 were as follows:

	2008	2007	2006
		(Thousands of Dollars)	
Compensation cost for share-based awards[(a)(b)]	$23,912	$24,900	$43,253
Tax benefit recognized in income	9,241	9,661	16,777
Total compensation cost capitalized	3,666	3,697	3,680

(a) Compensation costs for share-based payment arrangements is included in other operating and maintenance expense in the 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 totaled $18.6 million, $15.2 million and $15.0 million for the years ended 2008, 2007 and 2006, 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, 2008 and 2007, there was approximately $14.9 million and $6.5 million of total unrecognized compensation cost related to non-vested share-based compensation awards. Xcel Energy expects to recognize that cost over a weighted-average period of 2.4 years. Total unrecognized compensation expense will be adjusted for future changes in estimated forfeitures.

The amount of cash used to settle Xcel Energy's share-based compensation awards was $3.1 million and $7.8 million in 2008 and 2007, respectively.

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:

	2008	2007	2006
	(Thousands of Dollars)		
Cash received from stock options exercised	$214	$5,266	$10,231
Tax benefit realized for the tax deductions from stock options exercised	—	—	353

11. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 50 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2008:

- NSP-Minnesota had 2,279 and NSP-Wisconsin had 403 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2010. NSP-Minnesota also had an additional 209 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates through September 2010.
- PSCo had 2,159 bargaining employees covered under a collective-bargaining agreement, which expires in May 2009.
- SPS had 804 bargaining employees covered under a collective-bargaining agreement, which expires in October 2011.

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 52 percent in equity investments, 25 percent in fixed income investments and 23 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:

	2008	2007
Equity securities	55%	60%
Debt securities	26	22
Real estate	5	4
Cash	3	2
Nontraditional investments	11	12
	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 9.56 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 2008 and 2007 were below the assumed level of 8.75 percent while returns in 2006 exceeded the assumed level of 8.75 percent. Xcel Energy continually reviews its pension assumptions. In 2009, Xcel Energy will use an investment-return assumption of 8.50 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:

	2008	2007
	(Thousands of Dollars)	
Accumulated Benefit Obligation at Dec. 31	$2,435,513	$2,497,898
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$2,662,759	$2,666,555
Service cost	62,698	61,392
Interest cost	167,881	162,774
Plan amendments	—	(19,955)
Actuarial (gain) loss	(47,509)	23,325
Benefit payments	(247,797)	(231,332)
Obligation at Dec. 31	$2,598,032	$2,662,759
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$3,186,273	$3,183,375
Actual (loss) return on plan assets	(788,273)	199,230
Employer contributions	35,000	35,000
Benefit payments	(247,797)	(231,332)
Fair value of plan assets at Dec. 31	$2,185,203	$3,186,273
Funded Status of Plans at Dec. 31:		
Funded status	$ (412,829)	$ 523,514
Noncurrent assets	15,612	568,055
Noncurrent liabilities	(428,441)	(44,541)
Net pension amounts recognized on consolidated balance sheets	$ (412,829)	$ 523,514
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$1,220,721	$ 216,776
Prior service cost	102,842	123,426
Total	$1,323,563	$ 340,202
SFAS No. 158 Amounts Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Regulatory assets	$1,268,879	205,720
Regulatory liabilities	—	111,650
Deferred income taxes	22,294	9,780
Net-of-tax accumulated other comprehensive income	32,390	13,052
Total	$1,323,563	340,202
Measurement Date	Dec. 31, 2008	Dec. 31, 2007
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	6.75%	6.25%
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

At Dec. 31, 2008, one of Xcel Energy's pension plans had plan assets of $259.9 million, which exceeded projected benefit obligations of $244.3 million. At Dec. 31, 2007, the plan assets of $369.8 million exceeded projected benefit obligations of $253.6 million. All other Xcel Energy plans in the aggregate had plan assets of $1.9 billion and $2.8 billion and projected benefit obligations of $2.4 billion and $2.4 billion on Dec. 31, 2008 and 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 2006 through 2008 for Xcel Energy's pension plans and are not expected to require cash funding in 2009.

- Voluntary contributions were made to the PSCo Bargaining Pension Plan of $35 million in 2008, $35 million in 2007 and $30 million in 2006.
- Voluntary contributions were made to the NCE Non-Bargaining Pension Plan of $2 million in 2006. No voluntary contributions were made to the plan during 2007 or 2008.
- Xcel Energy projects cash funding of $70 million to $130 million in 2009. Pension funding contributions for 2010, which will be dependent on several factors including, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $250 million.

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:

	2008	2007	2006
	(Thousands of Dollars)		
Service cost	$ 62,698	$ 61,392	$ 61,627
Interest cost	167,881	162,774	155,413
Expected return on plan assets	(274,338)	(264,831)	(268,065)
Amortization of prior service cost	20,584	25,056	29,696
Amortization of net loss	11,156	15,845	17,353
Net periodic pension (credit) cost under SFAS No. 87	(12,019)	236	(3,976)
Credits not recognized due to effects of regulation	9,034	9,682	12,637
Net benefit (credit) cost recognized for financial reporting	$ (2,985)	$ 9,918	$ 8,661
Significant Assumptions Used to Measure Costs:			
Discount rate	6.25%	6.00%	5.75%
Expected average long-term increase in compensation level	4.00	4.00	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 2009 pension cost calculations will be 8.50 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) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $17.9 million in 2008, $21.8 million in 2007 and $18.3 million in 2006.

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:

	2008	2007
Equity and equity mutual fund securities	49%	67%
Fixed income/debt securities	29	21
Cash equivalents	22	11
Nontraditional investments	—	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:

	2008	2007
	(Thousands of Dollars)	
Change in Benefit Obligation:		
Obligation at Jan. 1	$ 830,315	$ 918,693
Service cost	5,350	5,813
Interest cost	51,047	50,475
Medicare subsidy reimbursements	6,178	2,526
Plan participants' contributions	13,892	13,211
Actuarial gain	(46,827)	(86,576)
Benefit payments	(65,358)	(73,827)
Obligation at Dec. 31	$ 794,597	$ 830,315
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$ 427,459	$ 406,305
Actual (loss) return on plan assets	(132,226)	24,623
Plan participants' contributions	13,892	13,211
Employer contributions	55,799	57,147
Benefit payments	(65,358)	(73,827)
Fair value of plan assets at Dec. 31	$ 299,566	$ 427,459
Funded Status at Dec. 31:		
Funded status	$(495,031)	$(402,856)
Current liabilities	(4,928)	(1,755)
Noncurrent liabilities	(490,103)	(401,101)
Net amounts recognized on consolidated balance sheets	$(495,031)	$(402,856)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 305,844	$ 202,748
Prior service credit	(9,205)	(11,380)
Transition obligation	58,479	73,056
Total	$ 355,118	$ 264,424
SFAS No. 158 Amounts Have Been Recorded as Follows Based upon Expected Recovery in Rates:		
Regulatory assets	$ 343,662	$ 154,661
Regulatory liabilities	—	97,835
Deferred income taxes	4,659	5,184
Net-of-tax accumulated other comprehensive income	6,797	6,744
Total	$ 355,118	$ 264,424
Measurement Date	Dec. 31, 2008	Dec. 31, 2007
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	6.75%	6.25%
Mortality table	RP 2000	RP 2000

Effective Dec. 31, 2008, Xcel Energy reduced its initial medical trend assumption from 8.0 percent to 7.4 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached is five 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, 2008	$ 80,774
1-percent decrease in APBO components at Dec. 31, 2008	(68,163)
1-percent increase in service and interest components of the net periodic cost	7,069
1-percent decrease in service and interest components of the net periodic cost	(5,835)

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 contributed $55.6 million during 2008 and expects to contribute approximately $63.1 million during 2009.

Benefit Costs — The components of net periodic postretirement benefit costs are:

	2008	2007	2006
	(Thousands of Dollars)		
Service cost	$ 5,350	$ 5,813	$ 6,633
Interest cost	51,047	50,475	52,939
Expected return on plan assets	(31,851)	(30,401)	(26,757)
Amortization of transition obligation	14,577	14,577	14,444
Amortization of prior service credit	(2,175)	(2,178)	(2,178)
Amortization of net loss gain	11,498	14,198	24,797
Net periodic postretirement benefit cost under SFAS No. 106	48,446	52,484	69,878
Additional cost recognized due to effects of regulation	3,891	3,891	3,891
Net cost recognized for financial reporting	$ 52,337	$ 56,375	$ 73,769
Significant assumptions used to measure costs (income):			
Discount rate	6.25%	6.00%	5.75%
Expected average long-term rate of return on assets (before tax)	7.50	7.50	7.50

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)			
2009	$ 224,558	$ 62,975	$ 5,725	$ 57,250
2010	226,585	64,468	6,117	58,351
2011	226,446	66,390	6,433	59,957
2012	230,763	67,400	6,804	60,596
2013	234,149	68,008	7,127	60,881
2014-2018	1,237,114	351,249	38,796	312,453

12. Detail of Interest and Other Income, Net

Interest and other income, net of nonoperating expenses, for the years ended Dec. 31 consisted of the following:

	2008	2007	2006
	(Thousands of Dollars)		
Interest income	$ 29,753	$ 24,093	$ 20,317
Equity income in unconsolidated affiliates	3,571	3,459	4,450
Other nonoperating income	5,725	4,352	5,253
Minority interest income	595	599	2,361
Insurance policy income (expense)	4,337	(21,548)	(27,637)
Other nonoperating expense	(4)	(7)	(659)
Total interest and other income, net	$ 43,977	$ 10,948	$ 4,085

13. 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 energy-related products and for various fuels used in generation and distribution activities. 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. 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, energy and energy-related instruments. Xcel Energy's risk-management policy allows management to conduct these activities within guidelines and limitations as approved by the 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 interest rate, utility commodity price, vehicle fuel price, 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 No. 133, are recorded on the consolidated balance sheets at fair value as derivative instruments valuation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification is dependent on the applicability of specific regulation.

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. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale, and vehicle fuel. Certain derivative instruments entered into to manage this variability are designated as cash flow hedges for accounting purposes. At Dec. 31, 2008, Xcel Energy had various commodity-related contracts classified as cash flow hedges extending through December 2010. Changes in the fair value of cash flow hedges are recorded in other comprehensive income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place.

At Dec. 31, 2008, Xcel Energy had $11.6 million of net losses in accumulated other comprehensive income related to commodity cash flow hedge contracts; $6.8 million 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 2008 and 2007.

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, 2008, Xcel Energy had $0.7 million of net losses in accumulated other comprehensive income related to interest rate hedges that are expected to be recognized in earnings during the next 12 months.

Xcel Energy had immaterial ineffectiveness related to interest rate cash flow hedges during 2008 and 2007.

The following table shows the major components of the derivative instruments valuation in the consolidated balance sheets at Dec. 31:

	2008		2007	
	Derivative Instruments Valuation — Assets	Derivative Instruments Valuation — Liabilities	Derivative Instruments Valuation — Assets	Derivative Instruments Valuation — Liabilities
	(Thousands of Dollars)			
Long-term purchased power agreements	$374,692	$353,531	$426,774	$401,313
Electric and natural gas trading and hedging instruments	52,968	54,307	51,106	21,694
Interest rate hedging instruments	—	8,503	535	20,223
Total	$427,660	$416,341	$478,415	$443,230

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 stockholder's equity and comprehensive income, is detailed in the following table:

	(Millions of Dollars)
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)
After-tax net unrealized losses related to derivatives accounted for as hedges	(12.1)
After-tax net realized losses on derivative transactions reclassified into earnings	0.4
Accumulated other comprehensive loss related to hedges at Dec. 31, 2008	$(13.1)

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. Xcel Energy holds no such instruments at Dec. 31, 2008. The fair market value of Xcel Energy's interest rate fair value hedges at Dec. 31, 2007, was a liability of approximately $2.6 million.

14. Financial Instruments

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

	2008		2007	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars)			
Nuclear decommissioning fund	$1,075,294	$1,075,294	$1,317,564	$1,317,564
Other investments	9,864	9,864	40,019	40,019
Long-term debt, including current portion	8,290,460	8,562,277	6,979,695	7,269,035

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 value of Xcel Energy's nuclear decommissioning fund is based on published trading data and pricing models, generally using the most observable inputs available for each class of security. The fair values of Xcel Energy's 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, 2008 and 2007. 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.

All unrealized gains and losses in the external decommissioning fund are recorded as a regulatory asset or liability pursuant to SFAS No. 71. The following tables provide the external decommissioning fund's approximate realized gains, losses and proceeds from the sale of securities for the years ended Dec. 31:

	2008	2007	2006
	(Thousands of Dollars)		
Realized gains	$ 65,779	$ 38,745	$310,066
Realized losses	107,272	35,794	32,412
Proceeds from sale of securities	914,514	669,070	958,294

***Guarantees* —** Xcel Energy provides guarantees and bond indemnities supporting certain 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 guarantees. On Dec. 31, 2008 and 2007, Xcel Energy had issued guarantees of up to $67.5 million and $75.2 million, respectively, with $18.2 and $17.5 million of known exposure under these guarantees, respectively. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of Dec. 31, 2008 and 2007, was approximately $27.9 million and $31.6 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

On Dec. 31, 2008, 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	$27.9	[a]	2009-2010, 2012, 2014, 2015 and 2022	[d]	N/A
Guarantee the indemnification obligations of Xcel Energy Wholesale Group Inc. under a stock purchase agreement[g]	Xcel Energy	17.5	$17.5	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	10.0	—	Continuing	[c]	N/A
Guarantee of customer loans for the Farm Rewiring Program	NSP-Wisconsin	1.0	0.3	Continuing	[e]	N/A
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	11.8	0.4	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 17 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, 2008 and 2007, there were $24.1 million and $20.1 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.

15. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of FTRs.

The following table presents, for each of these hierarchy levels, Xcel Energy's assets and liabilities that are measured at fair value on a recurring basis as of Dec. 31, 2008:

	Level 1	Level 2	Level 3	Counterparty Netting[a]	Net Balance
			(Thousands of Dollars)		
Assets:					
Cash equivalents	$ —	$ 50,000	$ —	$ —	$ 50,000
Nuclear decommissioning fund	465,936	499,935	109,423	—	1,075,294
Commodity derivatives	—	29,648	39,565	(16,245)	52,968
Total	$465,936	$579,583	$148,988	$(16,245)	$1,178,262
Liabilities:					
Commodity derivatives	$ 600	$ 78,714	$ 16,344	$(41,351)	$ 54,307
Interest rate derivatives	—	8,503	—	—	8,503
Total	$ 600	$ 87,217	$ 16,344	$(41,351)	$ 62,810

(a) FASB Interpretation No. 39 *Offsetting of Amounts Relating to Certain Contracts*, as amended by FASB Staff Position FIN 39-1 *Amendment of FASB Interpretation No. 39*, permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table presents the changes in Level 3 recurring fair value measurements for the year ended Dec. 31, 2008:

	Commodity Derivatives, Net	Nuclear Decommissioning Fund
	(Thousands of Dollars)	
Balance Jan. 1, 2008	$19,466	$108,656
Purchases, issuances, and settlements, net	(5,981)	12,198
Transfers out of Level 3	(3,962)	—
Gains recognized in earnings	2,129	—
Gains (losses) recognized as regulatory assets and liabilities	11,569	(11,431)
Balance Dec. 31, 2008	$23,221	$109,423

Gains on Level 3 commodity derivatives recognized in earnings for the year ended Dec. 31, 2008, include $3.7 million of net unrealized gains relating to commodity derivatives held at Dec. 31, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric revenues. Realized and unrealized gains and losses on short-term wholesale activities reflect the impact of regulatory recovery and are deferred as regulatory assets and liabilities. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

16. Rate Matters

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — MPUC

Base Rate

NSP-Minnesota Electric Rate Case — On Nov. 3, 2008, NSP-Minnesota filed a request with the MPUC to increase Minnesota electric rates by $156 million annually, or 6.05 percent. The request is based on a 2009 forecast test year, an electric rate base of $4.1 billion, a requested ROE of 11.0 percent and an equity ratio of 52.5 percent.

In December 2008, the MPUC approved an interim rate increase of $132 million, or 5.12 percent, effective Jan. 2, 2009. The primary difference between interim rate levels approved and NSP-Minnesota's request of $156 million is due to a previously authorized ROE of 10.54 percent and NSP-Minnesota's requested ROE of 11.0 percent.

A final decision from the MPUC is expected in the third quarter of 2009. The following procedural schedule has been established:

- Staff and intervenor direct testimony on April 7, 2009;
- NSP-Minnesota rebuttal testimony on May 5, 2009;
- Staff and intervenor surrebuttal testimony on May 26, 2009; and
- Evidentiary hearings are scheduled for June 2-9, 2009.

Electric, Purchased Gas and Resource Adjustment Clauses

TCR Rider — In November 2006, the MPUC approved a TCR rider pursuant to legislation, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. In December 2007, NSP-Minnesota filed adjustments to the TCR rate factors and implemented a rider to recover $18.5 million beginning Jan. 1, 2008. In March 2008, the MPUC approved the 2008 rider, but required certain procedural changes for future TCR filings if costs are disputed. On Oct. 30, 2008, NSP-Minnesota submitted its proposed TCR rate factors for proposed recovery in 2009, seeking to recover $14 million beginning Jan. 1, 2009. A portion of amounts previously collected through the TCR rider prior to 2009 has been included for recovery in the electric rate case described above. MPUC approval is pending.

RES Rider — In March 2008, the MPUC approved an RES rider to recover the costs for utility-owned projects implemented in compliance with the RES, and the RES rider was implemented on April 1, 2008. Under the rider, NSP-Minnesota could recover up to approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100 MW wind project, subject to true-up. In 2008, NSP-Minnesota submitted the RES rider for recovery of approximately $22 million in 2009 attributable to the Grand Meadow wind farm. On Feb. 12, 2009, the MPUC approved the rider request but required that the issue of whether these costs should be moved to base rates in the currently pending electric rate case or left in the rider, as NSP-Minnesota has proposed, to be addressed through supplemental testimony in the rate case.

MERP Rider — On Oct. 1, 2008, NSP-Minnesota filed a proposed MERP rider for 2009 designed to recover costs related to MERP environmental improvement projects. Under this rider, NSP-Minnesota proposes to recover $114 million in 2009, an increase of approximately $23 million over 2008. New rates went into effect automatically on Jan. 1, 2009 as stipulated. MPUC approval is still pending.

Annual Automatic Adjustment Report for 2007 — In September 2007, NSP-Minnesota filed its annual automatic adjustment reports 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, $1.2 billion in fuel and purchased energy costs, including $384 million of MISO 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. In October 2008, the MPUC voted to accept the 2007 gas annual automatic adjustment report. The 2007 annual electric automatic adjustment report is pending further MPUC action.

Annual Automatic Adjustment Report for 2008 — In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, $848.5 million in fuel and purchased energy costs, including $258.8 million of MISO charges, were recovered from Minnesota electric customers through the FCA. In addition, approximately $680 million of purchased natural gas and transportation costs were recovered through the PGA. The 2008 annual automatic adjustment reports are pending initial comments and MPUC action.

MISO ASM Cost Recovery — On May 9, 2008, NSP-Minnesota and several other Minnesota electric utilities filed jointly for MPUC regulatory approval to recover ASM costs through the Minnesota FCA cost recovery mechanism. The filing is pending MPUC action after an initial hearing on Dec. 18, 2008. The MPUC voted to approve FCA recovery of these charges, subject to refund, and required NSP-Minnesota to make a filing that demonstrates that there were benefits of the ASM market after one year of operation.

Gas Meter Module Failures — Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, N.D. area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function. In the May to July 2008 timeframe, NSP-Minnesota rebilled approximately 5,000 of these customers for their estimated consumption during the period the modules registered no consumption and then ceased rebilling as both the MPUC and NDPSC opened investigations into this matter.

On July 2, 2008, NSP-Minnesota received a letter from the NDPSC requesting further information on the module failure. Subsequent meetings between NSP-Minnesota and NDPSC staff were held in September and October 2008 to discuss NSP-Minnesota's progress in addressing various NDPSC concerns about NSP-Minnesota's response.

On Aug. 1, 2008, the MPUC opened a docket and issued a notice directing NSP-Minnesota to file information about the AMR module failure. NSP-Minnesota responded to the MPUC on Aug. 21, 2008, proposing to rebill affected customers for the unrecorded natural gas usage during the months that no consumption or intermittent usage was recorded. NSP-Minnesota proposed to employ the process provided by NSP-Minnesota's natural gas tariff and the MPUC's rules to estimate usage, which would be consistent with the process used whenever any other type of meter or module failure affecting the measurement of customer consumption occurs. The MOAG and the OES subsequently submitted comments on NSP-Minnesota's filing. The OES comments indicated support for the rebilling plan with certain conditions. The MOAG raised concerns about the timing of the remediation efforts, and questions whether customers should be responsible for the entire cost of the unbilled natural gas.

On Nov. 6, 2008, the MPUC reviewed the matter and directed NSP-Minnesota to provide additional information prior to making a final decision on the rebilling plan.

On Dec. 3, 2008, NSP-Minnesota made a filing with the NDPSC regarding its commitments and proposed remedies for rebilling affected customers. The filing outlined the proposed rebilling plan in detail, which committed to a 10-day, go-forward field response to customer inquiries regarding meter accuracy, offered an adjustment to the natural gas true-up to remove the commodity cost for the under recovered gas due to the rebilling process and indicated willingness to work with NDPSC staff on a service quality credit for customers experiencing a module failure.

On Dec. 19, 2008, NSP-Minnesota met with MPUC staff, the OES and MOAG and in January 2009 filed its response to the questions with the MPUC. NSP-Minnesota indicated a willingness to work with parties to develop a remedy for the current situation, and to develop prospective service quality standards to address this and other concerns around billing accuracy. NSP-Minnesota has determined that a number of AMR modules designed for commercial customers are defective and as a result is broadening efforts to evaluate the performance of both gas and electric AMR modules.

Annual Review of Remaining Lives — On Oct. 8, 2008, the MPUC approved NSP-Minnesota's service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities as well as the depreciation study for other gas and electric assets, effective Jan. 1, 2008. The net impact resulted in a reduction to depreciation expense of $5.6 million recognized in the third quarter, or $7.5 million on an annual basis.

Other

Nuclear Refueling Outage Costs — In November 2007, NSP-Minnesota requested a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request sought approval to amortize refueling outage costs over the period between refueling outages to better match revenues and expenses. This request would have reduced 2008 expenses for the NSP-Minnesota jurisdiction by approximately $25 million due to deferral and amortization over an 18-month period versus expensed as incurred.

On Sept. 16, 2008, the MPUC authorized NSP-Minnesota to use a deferral and amortization method for the nuclear refueling operating and maintenance costs effective Jan. 1, 2008. The ruling reduced operating and maintenance expenses, but also resulted in revenue deferrals. The net result is a positive adjustment to year-end earnings of approximately $21 million.

Pending and Recently Concluded Regulatory Proceedings — NDPSC and 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, which would be an $18.2 million impact to NSP-Minnesota due to the transfer of certain costs and revenues between base rates and the fuel cost recovery mechanism. The request was based on an 11.50 percent ROE, an equity ratio of 51.77 percent, and a rate base of approximately $242 million. Interim rates of $17.2 million became effective in February 2008.

The NDPSC approved a settlement agreement on Dec. 31, 2008, which calls for a base rate increase of $12.8 million, based on an authorized ROE of 10.75 percent. Key terms of the settlement are listed below:

- Adjustments in depreciation expenses related to service life changes for generation plants and removal rates for transmission and distribution plant, resulting in a $2.5 million decrease in the revenue deficiency.
- Sharing of wholesale margins, refunding to customers 85 percent of asset-based wholesale margins and 50 percent of non-asset-based margins through the fuel clause. Test year wholesale margins to be shared with customers are estimated to be $1.9 million.
- An electric rate moratorium, under which NSP-Minnesota agreed to not implement an increase in electric rates until Jan. 1, 2011.
- Sharing any earnings in excess of the authorized 10.75 percent ROE, providing customers 50 percent of any earnings above 10.75 percent and 75 percent of any earnings above 11.25 percent.
- The settlement outlines a process for more NDPSC involvement in NSP-Minnesota's resource planning process.

In addition to approving the settlement, the NDPSC terminated a 2005 filing regarding recovery of MISO Day 2 market charges, thus approving FCA recovery of all MISO Day 2 charges through the FCA retroactively and prospectively. Based on the final order, there will be an estimated interim rate refund of $6.3 million, which will be refunded back to customers by June 1, 2009. This refund was accrued for in 2008 and will have no impact on 2009 results. Final rates will be implemented for service on and after March 1, 2009.

Nuclear Refueling Outage Costs — In late 2007, NSP-Minnesota filed with both the NDPSC and SDPUC a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request is comparable to that filed with the MPUC. In February 2008, the NDPSC approved the request, indicating that appropriate cost recovery levels would be determined in the pending electric rate case.

The SDPUC approved the NSP-Minnesota's request to change the accounting method for nuclear refueling outage operating and maintenance cost from a direct expense method to a method that amortizes these costs over the period between outages.

MISO ASM Cost Recovery — On Dec. 24, 2008, NSP-Minnesota filed for NDPSC and SDPUC regulatory approval to recover MISO ASM costs via an FCA cost recovery mechanism. NSP-Minnesota requested a regulatory order prior to March 1, 2009, when ASM charges and revenues would affect the North Dakota and South Dakota FCA. On Feb. 11, 2009, the NDPSC concluded that FCA treatment of these costs was already provided for by the rate case settlement. Based on this information, NSP-Minnesota filed to withdraw its request. The MPUC granted the withdrawal request at its Feb. 25, 2009 open meeting. On Feb. 12, 2009 the SDPUC approved NSP-Minnesota's request.

NSP-Minnesota South Dakota TCR and ECR Rate Riders — In December 2008, the SDPUC approved two rate riders for recovery of transmission investments and environmental costs effective Feb. 1, 2009.

In February 2007, NSP-Minnesota filed a petition for approval of a tariff establishing a TCR rider for recovery of certain transmission investments. The TCR rider rate is set to recover approximately $1.9 million during 2009. In September 2007, NSP-Minnesota filed a petition for approval of a tariff establishing an environmental cost recovery (ECR) rider for recovery of pollution control equipment installed at NSP-Minnesota's A. S. King plant. The ECR Rider rate is set to recover approximately $2.5 million during 2009.

Both rate riders were allowed a return on equity of 9.5 percent according to the terms of their respective settlement agreements. However, if NSP-Minnesota makes a general rate filing utilizing a 2008 test year, the SDPUC may order that an appropriate ROE value to be utilized under the rider mechanism, subject to true-up for the period from July 1, 2008 to the effective date of the order.

Pending and Recently Concluded Regulatory Proceedings — FERC

MISO Long-Term Transmission Pricing — In October 2005, MISO filed a proposed change to its TEMT to regionalize future cost recovery of certain high voltage transmission projects. The tariff, called the Regional Expansion Criteria Benefits tariff, would recover certain eligible transmission investments from all transmission service customers in the MISO 15 state region. In November 2006, the FERC issued an order accepting the regional economic benefits (RECB) I tariff, including a 20 percent limitation on the portion of transmission reliability expansion costs that would be regionalized and recovered from all loads in the MISO region.

Transmission service rates in the MISO region have historically used a rate design in which the transmission cost depends on the location of the load being served, which is referred to as license plate rates. Costs of existing transmission facilities are thus not regionalized. In August 2007, MISO and its transmission owners filed a successor rate methodology, to be effective February 2008. American Electric Power (AEP) filed a competing rate proposal that would regionalize certain costs of the existing AEP system over the MISO and PJM RTO regions. The AEP proposal would shift several million dollars in transmission costs annually to the NSP System. In January 2008, the FERC rejected the AEP proposal. On Dec. 18, 2008, the FERC denied AEP's request for rehearing.

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 filed appeals to the U.S Court of Appeals for the District of Columbia seeking judicial review of the FERC's determinations of the allocation of RSG costs among MISO market participants. Xcel Energy 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 FERC-approved methodology for the recovery of RSG costs. In November 2007, the FERC issued an order instituting a proceeding to review evidence and to establish a RSG cost allocation methodology for market participants under the MISO TEMT. In March 2008, the MISO filed indicative tariff revisions that reflect an alternative mechanism for allocating RSG charges and costs. In August 2008, the FERC rejected this filing and issued an order commencing a hearing.

In November 2008, the FERC issued two orders related to RSG. One order requires the RSG charge allocation to include virtual supply transactions and requires resettlement of RSG charges retroactive to August 2007. The second order reversed a prior FERC decision and changed the RSG calculation methodology for the May 2006 to August 2007 retroactive period. Several parties have filed requests for rehearing of the November 2008 FERC orders, arguing that the change in RSG allocation should be prospective. The RSG-related dockets are pending FERC action.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings — PSCW

Base Rate

Electric and Gas 2008 Rate Case — In January 2008, the PSCW issued the final written order in NSP-Wisconsin's 2008 test year rate case, 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. The rate increase was based on a 10.75 percent ROE and a 52.5 percent common equity ratio. New rates went into effect in January 2008.

Electric Limited Reopener 2009 Rate Case — On Aug. 1, 2008, NSP-Wisconsin filed an application with the PSCW requesting authority to increase retail electric rates by $47.1 million, which represented an overall increase of 8.6 percent. In the application, NSP-Wisconsin requested the PSCW to reopen the 2008 base rate case for the limited purpose of adjusting 2009 electric rates to reflect forecasted increases in production and transmission costs, as authorized by the PSCW. No changes were requested to the capital structure or return on equity authorized by the PSCW in the 2008 base rate case.

NSP-Wisconsin and the intervenors entered into a stipulated agreement and on Dec. 30, 2008, the PSCW issued an order approving the stipulation and authorizing a $5.6 million rate increase. The original request of $47.1 million was reduced by $31.6 million due to the decline in market prices for fuel and purchased power, $5.5 million for a change in nuclear outage accounting and $4.4 million due to other adjustments.

Further, in accordance with the stipulation agreement, an estimated 2008 interim fuel surcharge refund liability of $9.8 million, recorded in 2008, will be offset by the $5.6 million 2009 rate increase, and the remaining liability will be refunded to customers in 2009, after the PSCW completes its final review of 2008 actual fuel costs.

Electric, Purchased Gas and Resource Adjustment Clauses

MISO ASM Cost Recovery — In the Dec. 30, 2008 order in NSP-Wisconsin's 2009 electric rate case, the PSCW included the costs and benefits associated with the MISO ASM in the fuel monitoring range established for 2009. Accordingly, ASM costs will flow through NSP-Wisconsin's fuel cost recovery mechanism in a similar fashion as all other fuel and purchased power costs. On Jan. 6, 2009, MISO began ASM operations.

Other

Nuclear Refueling Outage Costs — On Sept. 16, 2008, the MPUC approved NSP-Minnesota's request to adopt the deferral-and-amortization method of accounting for costs associated with refueling outages at its nuclear plants, effective Jan. 1, 2008. NSP-Wisconsin's 2008 Wisconsin retail electric retail rates were set based on the previous direct-expense accounting method, and recovered costs associated with 2008 refueling outages in 2008. For ratemaking purposes, NSP-Wisconsin switched to the deferral and amortization method effective Jan. 1, 2009. To reflect timing differences between when the revenue was received from customers versus when the corresponding expense will be billed through the interchange agreement, NSP-Wisconsin recorded a liability of $4.8 million. The liability will be fully amortized by the end of 2010.

2008 Electric Fuel Cost Recovery — On May 2, 2008, the PSCW approved, on an interim basis, NSP-Wisconsin's request of a $19.7 million surcharge, or 3.8 percent, on an annual basis, to recover forecast increases in fuel and purchased power costs. The interim fuel surcharge was in effect from May 6, 2008 to Dec. 31, 2008, and generated approximately $12.7 million in additional revenue in 2008. The revenues that NSP-Wisconsin collected were subject to refund with interest at a rate of 10.75 percent, pending PSCW review and final approval. The PSCW will conduct its final review of the interim fuel surcharge in 2009, after 2008 actual fuel costs are known.

NSP-Wisconsin actual retail fuel costs in 2008 were approximately $14.8 million less than assumed in the April 2008 forecast used to set the interim fuel surcharge, primarily due to lower market prices for fuel and purchased power. Based on actual fuel costs for 2008, NSP-Wisconsin has established a liability of $9.8 million to reflect the expected refund of interim surcharge revenues that will be determined by the PSCW. Notwithstanding the interim surcharge and lower than forecast fuel costs, NSP-Wisconsin's 2008 calendar year fuel costs exceeded authorized revenues by approximately $1.7 million, net of the anticipated refund.

In accordance with the stipulation agreement approved by the PSCW in NSP-Wisconsin's 2009 limited electric rate case, the estimated 2008 interim fuel surcharge refund liability of $9.8 million will be offset by the $5.6 million 2009 rate increase, and the remaining liability will be refunded to customers in 2009, after the PSCW completes its final review of 2008 actual fuel costs.

***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 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 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.

On July 3, 2008, the PSCW issued its notice of hearing in the rulemaking and requested public comments on the proposed revisions to the fuel rules. The proposed revisions to the rules were substantively the same as the version issued in August 2007, described above. A public hearing was held Aug. 4, 2008, and written comments were filed by the parties on Aug. 6, 2008. The utilities subject to the fuel rules, including NSP-Wisconsin, the Wisconsin Utilities Association, and Wisconsin Utility Investors, Inc. filed comments generally supporting the revised rule. An ad hoc coalition of intervenors, consisting of consumer and industrial customer groups, filed joint comments in opposition to the proposed rules.

The PSCW did not forward the proposed rules to the legislature for approval before the statutory deadline for action in the 2007-08 legislative session. At this time it is uncertain what, if any, additional action the PSCW will take with respect to this rulemaking, or the fuel rules in general.

***Bay Front Emission Controls Certificate of Authority* —** In March 2008, the PSCW issued a certificate of authority and order approving NSP-Wisconsin's application to install equipment relating to combustion improvement and NOx emission controls in boilers 1 and 2 at the Bay Front power plant in Ashland, Wis. Construction began in May and was completed in the fourth quarter of 2008. The new equipment and systems are in the testing and tuning phase, which is expected to be completed in the first quarter of 2009.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

Base Rate

***PSCo Electric Rate Case* —** On Nov. 14, 2008, PSCo filed a request with the CPUC to increase Colorado electric rates by $174.7 million annually, or approximately 7.4 percent. The rate filing is based on a 2009 forecast test year, an electric rate base of $4.2 billion, a requested ROE of 11.0 percent and an equity ratio of 58.08 percent.

On Feb. 13, 2009, parties filed answer testimony in the case. The CPUC staff accepted PSCo's forecast test-year and recommended an increase of $110 million based on a 10.37 percent ROE. The CPUC staff also recommended that the increase be split into two parts, the first part consisting of $69.9 million, effective in July 2009 and the remaining $40 million to take effect on or about Jan. 1, 2010 to coincide with the implementation of rates from the next rate case. In addition to ROE, the primary CPUC staff adjustments are related to the sales forecast, debt rate, incentive pay, and wage increases. The CPUC staff also recommends an earnings test to refund any earnings above authorized levels to customers.

The Office of Consumer Council (OCC) recommended a $3.8 million increase based on a historic test year increase of $69.9 million. The OCC recommended an ROE of 9.75 percent and an equity ratio of 53 percent. The OCC recommended adjustments to the cash working capital and rate case expense.

Other parties filing testimony affecting the revenue requirements were the Colorado Energy Consumers which supported use of a historic test year; Ratepayers United of Colorado, which recommended a 9.5 percent ROE; and Leslie Glustrom, a citizen intervenor, who raised concerns about the Comanche 3 project as well as PSCo's consulting and personal communication costs.

A final decision is expected in the summer of 2009. The following procedural schedule has been established:

- PSCo rebuttal testimony on March 20, 2009;
- Staff and intervenor surrebuttal testimony on April 10, 2009; and
- The hearing on the merits are scheduled for April 20 — May 1, 2009.

Natural Gas Rate Case — Phase II — In July 2007, the CPUC issued a final written order approving a natural gas rate increase of approximately $32.3 million, based on a 10.25 percent ROE and a 60.17 percent equity ratio. Final rates were implemented effective July 30, 2007, through a general rate schedule adjustment (GRSA) applied to all customer classes. Under the provisions of the settlement between PSCo and the CPUC, PSCo filed its Phase II (cost allocation and rate design) in April 2008 to spread the settled revenue requirement from its 2006 Phase I gas rate case among PSCo's customer classes.

In December 2008, the CPUC issued its final order in which the CPUC approved with certain exceptions PSCo's proposed reallocation of its revenue requirement, including the $32.3 million final written order referenced above, among rate classes.

In this same order, the CPUC rejected PSCo's proposal to raise its fixed monthly service and facilities charges. The CPUC also approved the recovery of PSCo's $15 million pilot low-income assistance program through customers' service and facilities charges. The costs of this low-income program are in addition to the $32.3 million base-rate increase approved in July 2007.

On Jan. 1, 2009, PSCo implemented the CPUC's approved reallocation of the revenue requirement, eliminated the GRSA and began recovering the costs of its low-income program.

Electric, Purchased Gas and Resource Adjustment Clauses

TCA Rider — In September 2007, PSCo filed with the CPUC a request to implement a TCA. In December 2007, the CPUC approved PSCo's application to implement the TCA rider. 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 TCA rider became effective on March 26, 2007. The CPUC also required 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 implemented a rider on Jan. 1, 2008, designed to recover approximately $4.5 million in 2008. PSCo filed updates to the TCA rider on Nov. 3, 2008, and new rates went into effect on Jan. 1, 2009, to recover approximately $18.0 million on an annual basis until the time rates in the pending rate case take effect.

Enhanced DSM Program — In July 2008, the CPUC issued an order approving PSCo's proposal to expand the DSM program and recover 100 percent of its forecasted expenses associated with the DSM program during the year in which the rider is in effect, beginning in 2009. An incentive mechanism was also approved to reward PSCo for meeting and exceeding program goals.

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 a 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. Parties have claimed that the total amount of transactions with PSCo subject to refund is $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 U. S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Court of Appeals remanded the proceeding back to the FERC. The Court of Appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The FERC has yet to act on this order on remand.

PSCo Wholesale Rate Case — In February 2008, PSCo requested a $12.5 million, or 5.88 percent, increase in wholesale rates, based on an 11.5 percent requested ROE. The $12.5 million total increase was composed of $8.8 million of traditional base rate recovery and $3.7 million of construction work in progress recovery for the Comanche 3 and Fort St. Vrain projects. The increase would be applicable to all wholesale firm service customers with the exception of Intermountain Rural Electric Cooperative, which would be under a rate moratorium until January 2009.

In March 2008, PSCo reached an agreement with Rural Electric Association (REA) customers Holy Cross, Yampa Valley and Grand Valley, which resolved all issues based on a "black box" settlement with an implied ROE of 10.4 percent. Parties filed the settlement with the FERC on April 17, 2008, with rates effective May 1, 2008. PSCo has reached an agreement with the cities of Burlington and Center, as well as Aquila under the same substantive terms and conditions as the REA settlement. This settlement was filed with the FERC on April 25, 2008. The settlements provide for:

- A traditional annual rate base rate increase of $6.6 million with AFDC continuing for Comanche Station and Fort St. Vrain.
- Implementation of new rates several months earlier than is typical in a disputed filing.
- The ability to implement rates in PSCo's next general rate case that will involve Comanche 3 costs upon a nominal suspension.

The FERC approved the settlement agreements on June 19, 2008.

Additionally, PSCo reached a settlement with Intermountain Rural Electric Association on similar terms. The FERC approved the settlement on Dec. 29, 2008. Rates took effect on Jan. 1, 2009. This agreement will increase base rates for Intermountain by $1.7 million in 2009.

SPS

Pending and Recently Concluded Regulatory Proceedings — PUCT

Base Rate

Texas Retail Base Rate Case — On June 12, 2008, SPS filed a rate case with the PUCT seeking an annual rate increase of approximately $61.3 million, or approximately 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue would decline by $33.1 million, primarily due to fuel savings from the LPP purchase power agreement.

The rate filing is based on a 2007 test-year adjusted for known and measurable changes, a requested ROE of 11.25 percent, an electric rate base of $989.4 million and an equity ratio of 51.0 percent. Interim rates of $18 million for costs associated with the LPP power purchase agreement went into effect in September 2008.

On Jan. 30, 2009, SPS filed an agreed upon motion to begin collecting interim rates of $57.4 million effective Feb. 1, 2009 for consumption occurring on or after that date. The ALJs issued an order authorizing this interim rate increase, which supersedes the $18 million interim rate increase that became effective in September 2008. On Feb. 20, 2009, the parties filed a unanimous settlement with the ALJs. The settlement:

- Provides for a base rate increase of $57.4 million;
- Approves depreciation rates that reduced depreciation expense by $5.6 million from currently authorized rates;
- Includes a mechanism for tracking and deferral of $2.6 million in renewable energy credit expenses until its next rate case;
- Provides that $3.2 million of annual energy efficiency expenses that SPS had requested through a rider be recovered through base rates (the parties agreed to litigate whether there should be a mechanism to address recovery of actual energy efficiency expenses to the extent that they are different than the amount included in the settlement rates);

- Allows SPS to implement the transmission cost recovery factor in 2009;
- Precludes SPS from filing to seek any other change in base rates until Feb. 15, 2010; and
- Resolves all fuel reconciliation issues for 2006-07 with one adjustment for $0.6 million related to the sharing of certain wholesale sales revenues.

The case and settlement will be remanded to the PUCT with action on the settlement expected later this spring.

***John Deere Wind Complaint* —** In June 2007, several John Deere Wind Energy 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 referred the complaint to the State Office of Administrative Hearings. On Aug. 14, 2008, JD Wind filed testimony claiming SPS has been underpaying JD Wind for its energy. Testimony has been filed and hearings were held. The ALJ will then recommend to the PUCT on how the dispute should be ruled. There is no deadline for the PUCT to take action.

Electric and Resource Adjustment Clauses

***TCR Factor Rulemaking* —** In November 2007, the PUCT adopted 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 between base rate cases.

Pending and Recently Concluded Regulatory Proceedings — NMPRC

Base Rate

***2007 New Mexico Retail 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 6.6 percent. The rate filing was based on a 2006 test year adjusted for known and measurable changes and included a requested ROE of 11.0 percent, an electric rate base of approximately $307.3 million and an equity ratio of 51.2 percent.

In August 2008, the NMPRC issued its final order authorizing an overall rate increase of $10.8 million based on a 10.18 percent ROE. This increase is based on a $7 million electric base rate increase and a rider to recover $3.8 million of restructuring costs. The NMPRC disallowed $3.5 million in rate base for historical DSM expenditures and certain rate case and prepaid pension expenses.

SPS implemented the base rates on Sept. 14, 2008.

***2008 New Mexico Retail Electric Rate Case* —** On Dec. 18, 2008, SPS filed with the NMPRC a request to increase electric rates in New Mexico by approximately $24.6 million, or 5.1 percent. The request is based on a historic test year (split year based on year-ending June 30, 2008), an electric rate base of $321 million, an equity ratio of 50 percent and a requested ROE of 12 percent. SPS also requested interim rates to allow it to begin recovering the cost of the LPP facility of approximately $7.6 million per year. The NMPRC has suspended the proposed rate request until Oct. 17, 2009, and has set the interim rate request for hearing on March 19, 2009. The NMPRC has assigned the main part of the case to a hearing examiner and has set a mandatory mediation with a settlement judge for March 12, 2009. The following procedural schedule has been established:

- Staff and intervenor direct testimony on May 8, 2009;
- SPS rebuttal testimony on May 29, 2009; and
- The hearing on the merits is expected to begin on June 8, 2009.

On Jan. 12, 2009, the NMPRC staff and the attorney general (AG) requested that the NMPRC suspend SPS' advice notice and deny the request for interim relief. The staff stated that the standard for interim relief requires clear and convincing evidence of a financial emergency, which SPS has failed to provide and stated that the proposal entails piecemeal and retroactive ratemaking. The AG stated that SPS' testimony does not rise to the level required for the NMPRC to grant interim relief.

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 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, which includes customer refunds of $11.7 million.
- At Dec. 31, 2007, a reserve had been previously established for this potential exposure, with no further expense accrual required.
- The settlement would also 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.
- Finally, the settlement provides for SPS to continue its use of the FPPCAC subject to additional reporting provisions.

On Aug. 26, 2008, the NMPRC issued a final order approving the unanimous stipulation.

***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. SPS filed its direct testimony on July 31, 2008.

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 adjustment charges to such customers (the Complaint). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to complainants. Cap Rock Energy Corporation (Cap Rock), another 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 ALJ issued an initial decision in the proceeding. The ALJ found that SPS should recalculate its FCAC billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by deducting from such costs the incremental fuel costs attributed to SPS' sales of system firm capacity and associated energy to other wholesale customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales made out of temporarily excess capacity. 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.

Golden Spread Complaint Settlement — In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. On April 21, 2008, the FERC approved the Settlement with a minor modification to the formula rate proposed by the FERC and accepted by the parties. The Settlement provides for:

- A $1.25 million payment by SPS to Golden Spread related to resolve a dispute concerning the quantities Golden Spread was entitled to take under its 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. 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' subsequent proceeding related to the period July 1, 2006 through Sept. 30, 2008, other than the method to be used to allocate demand related costs and provided for two sets of agreed-on rates that are dependent on the ultimate resolution of that issue.

For July 1, 2008 and beyond, Golden Spread will be under a formula rate for power supply service. The rate will be based on actual data the most recent historic year adjusted for known and measurable changes and trued up to the actual performance in the subsequent calendar year.

Order on Wholesale Rate Complaints — In April 2008, the FERC issued its Order on the Complaint applied to the remaining non-settling parties. The Order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006, for SPS' full requirements customers who pay traditional cost-based rates and requires certain refunds.

- **Base Rates:** The FERC determined: (1) the ROE should be 9.33 percent; (2) rates should be based on a 12 CP allocator; and (3) the treatment of market based rate contracts in the test year should be to credit revenues to the cost of service rather than allocating costs to the agreements. The revenue requirement established by the FERC results in proposed revenues that are estimated to be approximately $25 million, or approximately $6.9 million below the level charged these customers during this 18-month period. Rates for full requirements customers, the New Mexico Cooperatives and Cap Rock, as well as an interruptible contract with PNM for the period beginning July 1, 2006, are the subject of settlements that have either been approved or are pending before the FERC. These settlements are described in Wholesale 2005 Power Base Rate Application below.
- **Fuel Clause:** The FERC determined that the method for calculating fuel and purchased energy cost charges to the complaining customer is to deduct from such costs incremental fuel and purchased energy costs, which it is attributing to SPS' market based intersystem sales on the basis that these are "opportunity" sales under its precedent. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005 (the refund effective date in the case). The FERC ordered SPS to file a compliance filing calculating its refund obligation and implement the instructions in the order in calculating its FCAC charges going forward from that date. While the order is subject to interpretation with respect to aspects of the calculation of the refund obligation, SPS does not expect its refund obligation to its full requirements customers from Jan. 1, 2005 through March 31, 2008, to exceed $11 million. PNM has filed a separate complaint that any refund obligation to PNM will be determined in that docket. SPS is reviewing the Order and has not yet determined whether to seek rehearing.
- The FERC also ruled on two other FCA issues. First, it required that wind contracts be evaluated on an individual contract basis rather than in aggregate. Second, the FERC determined that an after-the-fact screen should be applied to all QF purchases to determine if they are economic. While this review will require additional effort, it is not expected that this will result in additional refunds as all of the individual wind contracts as well as the QF purchases are typically economic when compared to market energy prices.

Several parties, including SPS, filed requests for rehearing on the order. These requests are pending before the FERC. In July 2008, SPS submitted its compliance report to the FERC. In the report, SPS has calculated the base rate refund for the 18-month period to be equal to $6.1 million and the fuel refund to be equal to $4.4 million. Several wholesale customers have protested the calculations. Once the final refund amounts are approved by the FERC, interest will be added to the refund due the full requirements customers. As of Dec. 31, 2008, SPS has accrued an amount sufficient to cover the estimated refund obligation.

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. 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. In September 2008, the FERC issued an order accepting the contested partial settlement with PNM.

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 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.

The proposed rates would be updated annually each July 1 based on SPS' prior year actual costs and loads plus the revenue requirements associated with projected current year transmission plant additions. The proposed ROE is 12.7 percent, including a 50 basis point adder for SPS' participation in the SPP RTO. The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC accepted 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 ROE that it will determine in this proceeding as a result of SPS' participation in the SPP RTO. The filed rates, updated for 2007 actual costs and projected 2008 transmission plant additions, were placed into effect on July 6, 2008, subject to refund. The SPS and SPP rate filings are now in settlement procedures. The ultimate outcome of the rate filings is not known at this time.

SPS 2008 Wholesale Rate Case — On March 31, 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. On April 21, 2008, a motion for dismissal and protest was filed by the four eastern New Mexico cooperatives.

In SPS' answer to the motions to intervene and protest, SPS renewed its request for a nominal suspension of 60 days and asked the FERC to consider such a nominal suspension in exchange for SPS' acceptance of two conditions. The first condition was that SPS would agree to a ROE of no more than 10.25 percent and second, SPS would agree to use a 12 CP demand allocator for the period the rates will be in effect. The SPS answer would result in an annual revenue increase of $9.9 million or an overall 3.4 percent increase.

On May 30, 2008, the FERC conditionally accepted and suspended the rates and established hearing and settlement procedures. The FERC granted a one-day suspension of rates instead of 180 days. The LPP plant achieved commercial operations in September 2008 and the proposed base rates, based on a 10.25 percent ROE and a 12-CP demand allocator, became effective, subject to refund. A pre-hearing conference was held Jan. 29, 2009, where a procedural schedule for the hearing was established and a preliminary joint list of issues was discussed.

17. Commitments and Contingent Liabilities

Commitments

Capital Commitments — As of Dec. 31, 2008, the estimated cost of capital requirements of Xcel Energy and its subsidiaries and the capital expenditure programs is approximately $1.8 billion in 2009, $2.3 billion in 2010 and $2.4 billion in 2011. Xcel Energy's capital forecast includes the following major projects:

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. A renewed operating license was approved and issued for Monticello by the NRC in November 2006 licensing the plant to operate until 2030, and the MPUC order approving the spent fuel storage capacity needed to support plant operations until 2030 went into effect in June 2007. The application to renew Prairie Island's operating licenses was submitted to the NRC in April 2008 and the application for a certificate of need for additional spent fuel storage capacity to support 20 additional years of plant operation was submitted to the MPUC in May 2008. Final state and federal approvals are expected in 2010.

NSP-Minnesota is pursuing capacity increases of Monticello and Prairie Island that will total approximately 230 MW, to be implemented, if approved, between 2009 and 2015. The life extension and capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2's original steam generators, currently planned during the refueling outage in 2013. Total capital investment for these activities is estimated to be over $1 billion between 2006 and 2015. NSP-Minnesota submitted the certificate of need and site permit applications for Monticello's power uprate in the first quarter of 2008 and the certificate of need and site permit applications for Prairie Island's power uprate in the second quarter of 2008. The MPUC approved the Monticello power uprate certificate of need and site permit in December 2008. Action by the MPUC on the Prairie Island power uprate certificate of need and site permit is expected in fourth quarter of 2009.

Wind Generation — NSP-Minnesota plans to invest approximately $900 million over three years for a 201 MW project in southwestern Minnesota's Nobles County, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project, expected to be operational by the end of 2010 and 2011, respectively. NSP-Minnesota is in the process of seeking regulatory approval for the projects, which would be eligible for rider recovery in Minnesota.

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 $1.7 billion, with major construction targeted to begin in 2010 and ending three to five years later. Xcel Energy's investment is expected to be approximately $900 million depending on the route and configuration approved by the MPUC. 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 a similar TCR mechanism passed in South Dakota. Cost recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

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. New state-of-the-art emission control equipment was placed in-service for the Allen S. King plant in 2007, and the existing High Bridge facility was replaced with a 575 MW natural gas combined cycle unit, which went into service in May 2008. The final phase of the MERP program, the new Riverside combined cycle plant, is currently in start-up and scheduled to be in-service by May 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 $1.3 billion, with major construction initiated in 2006 and is expected to be completed in the fall of 2009. The CPUC has approved sharing one-third ownership of this plant.

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.

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 2009 and 2040. In total, Xcel Energy is committed to the minimum purchase of approximately $2.7 billion of coal, $345.3 million of nuclear fuel and $4.4 billion of natural gas, including $3.5 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 2032. 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.

At Dec. 31, 2008, 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)
2009	$ 514.1
2010	509.7
2011	498.9
2012	422.8
2013	358.7
2014 and thereafter	1,716.9
Total	$4,021.1

Variable Interest Entities (VIE) — Xcel Energy has certain long-term power purchase agreements with independent power producing entities that contain tolling arrangements under which Xcel Energy procures the fuel required to produce the energy purchased. Xcel Energy enters into these agreements to meet electric system capacity and energy needs. Xcel Energy is not subject to risk of loss from the operations of these entities. Xcel Energy has evaluated such entities for possible consolidation under FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, (FIN 46R) and has concluded that these entities are not required to be consolidated in Xcel Energy's consolidated financial statements. The significant qualitative factors considered evaluating purchase power agreements under FIN 46R include length and terms of the contract and operational, fuel price and financing risk. When necessary, a quantitative analysis demonstrated that Xcel Energy would absorb less than 50 percent of the expected gains or losses. Significant assumptions used in the quantitative analysis by Xcel Energy, to determine the primary beneficiary, include an inflation rate equal to the Bureau of Labor Statistics 10 year average, estimated future fuel and electricity prices, future operating cash flows, an incremental borrowing rate, the expected life of the plant and a debt to equity financing ratio.

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:

	2008	2007
	(Millions of Dollars)	
Storage, leaseholds and rights	$ 40.5	$ 40.5
Gas pipeline	20.7	20.7
	61.2	61.2
Accumulated amortization	(17.8)	(16.3)
Total property held under capital leases	$ 43.4	$ 44.9

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, cars and power-operated equipment, are accounted for as operating leases. Total rental expense under operating lease obligations for Xcel Energy and its subsidiaries was approximately $176.9, $105.2, and $60.3 million for 2008, 2007, and 2006, respectively. Included in total rental expense were purchase power agreement payments of $130.3 million, $55.7 million, and $14.5 million in 2008, 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 EITF No. 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[(a)(b)]	Total Operating Leases	Capital Leases
	(Millions of Dollars)			
2009	$26.1	$ 160.3	$ 186.4	$ 6.0
2010	22.9	157.4	180.3	5.8
2011	20.3	147.6	167.9	5.7
2012	17.2	144.4	161.6	5.5
2013	16.7	148.1	164.8	5.3
Thereafter	38.1	2,322.0	2,360.1	51.5
Total minimum obligation				79.8
Interest component of obligation				(36.4)
Present value of minimum obligation				$ 43.4

(a) Amounts not included in purchase power agreement estimated future payments above.

(b) Purchase power agreement operating leases contractually expire through 2033.

WYCO **—** Xcel Energy has invested approximately $128 million as of Dec. 31 2008 for construction of WYCO's High Plains gas pipeline and the related Totem gas storage facilities. The High Plains gas pipeline began operations in 2008 and the Totem gas storage facilities are expected to begin operations in 2009. The gas pipeline and storage facilities will be leased under a FERC-approved agreement to Colorado Interstate Gas Company, a subsidiary of El Paso Corporation.

Technology Agreements **—** 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 2008, Xcel Energy paid IBM $110.8 million under the contract and $0.2 million for other project business. The contract also has a committed minimum payment each year from 2009 through September 2015. Payments under this obligation are $19.9 million, $19.6 million, $19.1 million, $18.9 million, $18.7 million and $32.5 million for 2009 to 2013 and thereafter, respectively.

On Aug. 1, 2008, Xcel Energy entered into a contract with Accenture for information technology services, which begins on Feb. 1, 2009 and extends through 2014. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. The contract also has a committed minimum payment each year from 2009 through 2014. Payments under this obligation are $11.4 million, $11.6 million, $11.6 million, $11.8 million, $12.0 million and $12.3 million for 2009 to 2013 and thereafter, respectively.

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 (PRPs) 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 or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former 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 PRP that sent hazardous materials and wastes. At Dec. 31, 2008, the liability for the cost of remediating these sites was estimated to be $71.3 million, of which $1.5 million was considered to be a current liability.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been 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 Chequamegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until early 2009. In October 2004, the state of Wisconsin 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 state also alleges a claim for forfeitures and interest. All costs paid to the state are expected to be recoverable in rates.

In November 2005, the 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. In 2008, NSP-Wisconsin spent $0.8 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 October 2007, the EPA approved the series of reports included in the remedial investigation report. On Dec. 4, 2008, the EPA approved the final feasibility study submitted by NSP-Wisconsin. The final feasibility study sets forth a range of remedial options under consideration by the EPA for the site but does not select a remedy. The EPA Remedy Review Board met in November 2008 to consider the remedial approach proposed by the Remedial Project Manager (RPM) for EPA Region 5. The remedy the EPA will suggest for the site, following input from the EPA Remedy Review Board, will be set forth in its Proposed Plan which is currently expected in early 2009. The Proposed Plan will undergo public comment before the EPA makes its final remedy selection in its record of decision, which is currently expected to be issued in late 2009. The estimated remediation costs for the site range between $49.7 million and $137.5 million, including costs set forth in the revised feasibility study, as well as estimates for WDNR past oversight costs, outside legal and consultant costs and work plan costs.

In addition to potential liability for remediation, 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 accurately quantify its potential exposure for NRD at the site, but has recorded an estimate of its potential liability based upon its best estimate 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 and the time frame over which the amounts may be paid out are not determinable. NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site. NSP-Wisconsin has recorded a liability of $65.9 million based on management's best estimate of remediation 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 be credited to ratepayers.

Fort Collins MGP 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 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 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 $2.8 million. This reflects a reduction in estimated EPA oversight costs over the life of the project, based upon the most recent EPA oversight billing.

In April 2005, PSCo brought a contribution action against Schrader and related parties (collectively “Schrader”) alleging Schrader 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 November 2008, PSCo and Schrader entered into a settlement agreement whereby Schrader paid $2.75 million to PSCo, and will make additional payments of $50,000 per year for the next five years for a total settlement of $3.0 million. Net proceeds from the settlement will be credited to customers.

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 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.

Other Environmental Requirements

CAIR — In March 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The objective of CAIR was 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. In July 2008, the U. S. Court of Appeals for the District of Columbia vacated CAIR and remanded the rule to EPA. On Dec. 23, 2008, the court reinstated CAIR while the EPA develops new regulations in accordance with the court’s July opinion.

As currently written, 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.

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. The remaining capital investments for NOx controls in the SPS region are estimated at $ 4.5 million. For 2009, the estimated NOx allowance compliance costs are $2.5 million. Annual purchases of SO_2 allowances are estimated in the range of $3 million to $17 million each year, beginning in 2013, for phase I, based on expected allowance costs and fuel quality at the end of 2008.

The EPA has drafted a proposed rule to stay the effectiveness of CAIR in Minnesota. As such, cost estimates are not included at this time for NSP-Minnesota. Purchases of NOx allowances for NSP-Wisconsin are estimated at $2.1 million in 2009.

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 the CAMR, which regulated mercury emissions from power plants. In February 2008, the U.S. Court of Appeals for the District of Columbia 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 in the following sections.

In Colorado, the AQCC passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and other specified units by 2014. The expected cost estimate for the Pawnee Generating Station is $2.3 million for capital costs with an annual estimate of $1.4 million for absorbent expense. PSCo is evaluating the emission controls required to meet the state rule for the remaining units and is currently unable to provide a total capital cost estimate.

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 NSP-Minnesota, 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.

On Dec. 21, 2007, NSP-Minnesota filed mercury emission reduction plans for two dry scrubbed units, Sherco Unit 3 and A. S. King, as well as a comprehensive emissions reduction and capacity upgrade proposal for Sherco Units 1 and 2 (wet scrubbed units). A revised specific mercury reduction proposals for these units will be filed by Dec. 31, 2009, as required by the legislation. Current plans are to install a sorbent injection system at both A. S. King and Sherco Unit 3. Implementation would occur by Dec. 31, 2009, at Sherco Unit 3 and by Dec. 31, 2010, for A. S. King. For these units, the current total capital cost estimate is $8.5 million, with the annual cost estimate of $4.3 million for A. S. King and $4.2 million for Sherco Unit 3. For Sherco Units 1 and 2, the current cost estimate is $13.6 million for capital and $10 million for annual expenses.

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. On Aug. 26, 2008, NSP-Minnesota filed a request with the MPUC to increase the deferral to $19.4 million as NSP-Minnesota anticipated exceeding the authorized deferral amount in September 2008. On Nov. 6, 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans.

Voluntary Capacity Upgrade and Emissions Reduction Filing — 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 A. S. King plants. Currently, the estimated project costs are approximately $8.5 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco Units 1 and 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 to add additional capacity and to achieve even lower emissions. If selected, these alternatives could range from $90.8 to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota's investments are subject to MPUC approval of a cost recovery mechanism. The MPCA has issued its assessment that the Sherco Unit 3 and A. S. King plans are appropriate. In light of recent significant changes in the national economy, lower forecast of energy consumption, and new information concerning an emerging technology that may be more cost effective, NSP-Minnesota filed a request with the MPUC to withdraw the plan on Nov. 6, 2008, to allow NSP-Minnesota to reevaluate alternatives. The MPUC granted the withdrawal request on Dec. 9, 2008.

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 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.

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 AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of BART will cost approximately $254 million in capital costs, which includes approximately $113 million in environmental upgrades for the existing Comanche Station Units 1 and 2 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. Colorado's state implementation plan has been submitted to EPA for approval. In January 2009, the CAPCD initiated a joint stakeholder process to evaluate what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado's Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The stakeholder process will continue throughout 2009.

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. In July 2008, the U. S. Circuit Court of Appeals for the District of Columbia vacated CAIR and remanded the rule to the EPA. In December 2008, the Court of Appeals reinstated CAIR while the EPA develops new regulations in accordance with the Court's July opinion. For Minnesota facilities, however, the EPA has drafted a proposed rule that would stay the effectiveness of CAIR within the state. Therefore, the MPCA has reestablished the BART process and requested that companies with BART-eligible units inform the MPCA whether the company will rely on the initial 2006 BART determination submittal or if they intend to submit a revised analysis. On Nov. 13, 2008, NSP-Minnesota submitted a revised BART alternatives analysis letter to the MPCA to account for increased construction and equipment costs. The underlying conclusions and proposed emission control equipment, however, remain unchanged from the original 2006 BART analysis.

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 (BTA) 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. In April 2008, the U.S. Supreme Court granted limited review of the Second Circuit's opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. A decision is not expected until 2009.

The MPCA exercised its authority under "best professional judgment" to require Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake's impact on aquatic wildlife. NSP-Minnesota is discussing alternatives with the local community and regulatory agencies to address this concern.

Maddox Station Groundwater — The New Mexico Environment Department is requiring wastewater activity at Maddox Station to be permitted. SPS is developing the engineering wastewater management facilities and submitted the permit application in July 2008. The estimated cost of the project is $1.8 million with an anticipated completion date in June 2009.

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 sought 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 asserted 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. On Aug. 26, 2008, Xcel Energy and the NYAG reached a settlement regarding this matter whereby Xcel Energy, without admitting or denying any violation of law or wrongdoing, agreed to voluntarily expand and/or continue to provide a discussion of climate change and possible attendant risks in its 10-K filings with the SEC. A settlement was reached, and it did not have a material effect on the consolidated financial statements of Xcel Energy.

PSCo Notice of Violation (NOV) — In July 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche Station and Pawnee Station 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. PSCo 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.

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 FASB Statement 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, radiation sources 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. Additional AROs have been recorded for NSP-Minnesota and PSCo steam production plant related to radiation sources in equipment used to monitor the flow of coal, lime and other materials through feeders.

In 2008, NSP-Minnesota recognized an ARO associated with the wind turbines at the new Grand Meadow Wind Farm. The turbines are located on leased property, and under the lease agreements, must be removed when no longer used. The recognition of the ARO was due to the units being placed in service in the fourth quarter of 2008.

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 18 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, 2008 and Dec. 31, 2007, respectively:

	Beginning Balance Jan. 1, 2008	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2008
			(Thousands of Dollars)			
Electric Utility Plant:						
Steam production asbestos	$ 35,807	$21,721	$(500)	$ 2,165	$ 33,948	$ 93,141
Steam production ash containment	22,539	—	—	1,275	(5,171)	18,643
Steam production radiation sources	—	335	—	2	—	337
Nuclear production decommissioning	1,209,746	—	—	71,370	(267,774)	1,013,342
Wind production	—	7,408		39		7,447
Electric transmission and distribution	270	—	—	16	27	313
Gas Utility Plant:						
Gas transmission and distribution	45,505	—	—	1,127	(45,752)	880
Common Utility and Other Property:						
Common general plant asbestos	1,277	—	—	70	(268)	1,079
Total liability	$1,315,144	$29,464	$(500)	$76,064	$(284,990)	$1,135,182

The fair value of NSP-Minnesota assets legally restricted, for purposes of settling the nuclear ARO is $1.1 billion as of Dec. 31, 2008, including external nuclear decommissioning investment funds and internally funded amounts.

A new decommissioning study filed with the MPUC in 2008 proposed extension of the final removal date of the Monticello and Prairie Island nuclear plants by 14 and 26 years, respectively, effective Jan. 1, 2009. As a result of the studies for the Monticello and Prairie Island nuclear plants, the nuclear production decommissioning ARO and related regulatory asset decreased by $128.5 million and $139.3 million, respectively, in the fourth quarter of 2008.

Revisions to prior estimates were made for asbestos, ash ponds, gas distribution and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

	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

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:

	2008	2007
	(Millions of Dollars)	
NSP-Minnesota	$354	$342
NSP-Wisconsin	96	94
PSCo	379	374
SPS	96	96
Total Xcel Energy	$925	$906

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $12.5 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 $12.2 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 $117.5 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 $17.5 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 Oct. 29, 2008. The next adjustment is due on or before Oct. 29, 2013.

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 $16.1 million for business interruption insurance and $29.7 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 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 et al.* 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 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.

In April 2005, Judge Pro granted defendants' motion to dismiss in *Texas-Ohio Energy* based upon the filed rate doctrine. 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 U.S. Court of Appeals for the Ninth Circuit. In September 2007, the 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. e prime and some other defendants were dismissed from the *Breckenridge Brewery* lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

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' summary judgment motions are pending in the *Learjet* and *J.P. Morgan* matters. In January 2009, the parties reached a settlement agreement in principle in the *Abelman Art Glass, Ever Bloom, Fairhaven Power Company, Texas-Ohio Energy*, and *Utility Savings and Refund Services* cases. The terms of the settlement in principle will not have a material financial effect upon Xcel Energy. Per court order, discovery in most of the remaining cases must be completed by Sept. 5, 2009. Trial for all cases venued in Nevada will likely be set for late 2009 or early 2010.

In November 2007, the *Missouri Public Service Commission* case was remanded to Missouri state court. On Jan. 13, 2009, the Missouri state court granted defendants' motion to dismiss plaintiff's complaint for lack of standing.

Environmental Litigation

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 U.S. Court of Appeals for the Second Circuit. In June 2007 the 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 CAA. In July 2007, in response to the request of the Court of Appeals, 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 U.S. Court of Appeals for the Fifth Circuit. Oral arguments were presented to the Court of Appeals on Aug. 6, 2008. Pursuant to the court's order of Sept. 26, 2008, re-argument was held on Nov. 3, 2008. No explanation was given for the order. The Court of Appeals has taken the matter under advisement.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utilities, oil, gas and coal companies. The suit was brought on behalf of approximately 400 native Alaskans, the Inupiat

Eskimo, who claim that Defendants' emission of CO_2 and other GHG contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence, the entire village must be relocated at a cost of between $95 million and $400 million. Plaintiffs assert a nuisance claim under federal and state common law, as well as a claim asserting "concert of action" in which defendants are alleged to have engaged in tortious acts in concert with each other. Xcel Energy was not named in the civil conspiracy claim. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008. The matter has now been fully briefed, with oral arguments set for May 19, 2009. It is unknown when the court will render a decision.

Employment, Tort and Commercial Litigation

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 oral arguments took place on Sept. 11, 2008. Mediation took place on Oct. 14, 2008, but the matter was not resolved. In December 2008, the Court of Appeals issued a decision ordering dismissal of Plaintiffs' claims for injunctive relief, but otherwise rejecting NSP-Minnesota's contentions and ordering the matter remanded for trial. The Minnesota Supreme Court subsequently granted NSP-Minnesota's petition for further review on Feb. 17, 2009.

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 Colorado state court in Denver. 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. On June 16, 2008, Qwest filed its appellate brief. The matter has been fully briefed by the parties and oral arguments were presented on Feb. 18, 2009. PSCo is currently awaiting a decision by the court.

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. In January 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. Plaintiffs petitioned the Minnesota Supreme Court for discretionary review, and the Supreme Court granted the petition. Oral argument took place on Nov. 4, 2008. It is unknown when a decision will be issued.

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 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 Minnesota Court of Appeals 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.

In April 2008, the Court of Appeals issued an order staying briefing and other appellate proceedings until further order of the court. The order was issued in response to NSP-Wisconsin's request that oral argument be deferred pending a decision by the Wisconsin Supreme Court in *Plastics Engineering Co. vs. Liberty Mutual Insurance Co*. On Jan. 29, 2009, the Wisconsin Supreme Court issued its decision in Plastics Engineering Co., adopting an all sums method of allocating damages when an injury spans multiple, successive policy periods. On Feb. 3, 2009, the Court of Appeals issued an order dissolving the stay and establishing a briefing schedule. NSP-Wisconsin has until March 9, 2009 to file a supplemental brief addressing the impact of *Plastics Engineering Co*. The insurers have until April 9, 2009 to file their initial briefs on appeal. Thereafter, NSP-Wisconsin will reply to the insurers' briefs.

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 be credited 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. Department of Energy's (DOE) 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, and NSP-Minnesota cross-appealed on the cost of capital issue. In April 2008, the DOE asked the Court of Appeals to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court of Appeals granted the request. In December 2008, NSP-Minnesota made a motion in the Court of Appeals to lift the stay, which was denied by the Court of Appeals in February 2009. Results of the judgment will not be recorded in earnings until the appeal and regulatory treatment and amounts to be shared with ratepayers have 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 U.S. 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 will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, 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, but the stay was lifted in November 2008. The court's scheduling order provides that the parties will exchange expert reports in 2009, and that all discovery will be completed by the end of 2009. Trial is expected to take place in 2010.

Fargo Gas Explosion — In September 2008, an explosion occurred at a duplex in Fargo, N.D. The explosion destroyed one side of the duplex and resulted in injuries to some of the residents. Xcel Energy subsequently provided a report to the U.S. Dept. of Transportation Pipeline and Hazardous Materials Safety Administration stating that natural gas migrated into the house and was ignited by an unknown source. Investigators identified a natural gas leak the size of a pinhole located 18 inches underground. The property owners and attorneys representing the injured residents have put Xcel Energy on notice of potential claims. Investigation into the incident is continuing.

Mallon vs. Xcel Energy Inc. — In August 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in Colorado state court against Theodore Mallon and TransFinancial Corporation seeking damages for, among other things, breach of contract and breach of fiduciary duties associated with the sale of COLI policies. In May 2008, Xcel Energy, PSCo and PSRI filed an amended complaint that, among other things, adds Provident Life & Accident Insurance Company (Provident) as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. On June 23, 2008, Provident filed a motion to dismiss the complaint. On Oct. 22, 2008, the court granted Provident's motion in part, but denied the motion with respect to a majority of the core causes of action asserted by PSCo, Xcel Energy Inc. and PSRI. In January 2009, the court granted defendant Mallon's motion to amend his answer to, among other things, add a counterclaim for breach of contract and fraud against plaintiffs PSRI, PSCo and Xcel Energy. Xcel Energy believes the counterclaims are without merit and intend to vigorously defend against them.

Cabin Creek Hydro Generating Station Accident — In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo's Cabin Creek Hydro Generating Station near Georgetown, Colo. This work was being performed as part of a corrosion prevention effort. A fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U.S. Chemical Safety Board and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008 the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17, 2008. The Court ordered this proceeding stayed until March 3, 2009 and indicated an extension of the stay is possible. A lawsuit has been filed in Colorado state court in Denver on behalf of four of the deceased workers and four of the injured workers (Foster, et. al. v. PSCo, et. al.). PSCo and Xcel Energy are named as defendants in that case, along with RPI Coatings and related companies and the two other contractors who also performed work in connection with the relining project at Cabin Creek. A second lawsuit (Ledbetter et. al vs. PSCo et. al) has also been filed in Colorado state court in Denver on behalf of three employees allegedly injured in the accident. A third lawsuit was filed on behalf of one of the deceased RPI workers in the California state court (Aguirre v. RPI, et. al.), naming PSCo, RPI, and the two other contractors as defendants. The court subsequently dismissed the Aguirre lawsuit, and it is anticipated that the plaintiff will refile the lawsuit in Colorado. Xcel Energy, Inc and PSCo intend to vigorously defend themselves against the claims asserted in all three lawsuits.

Fru-Con Construction Corporation vs. 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 Texas state court. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the decision to the Court of Appeals for the Third Supreme Judicial District. In November 2008, the Court of Appeals issued an opinion affirming the decision in favor of SPS. In December 2008, LCEC filed a petition for review with the Supreme Court of Texas. Consistent with the standard practice before the Texas Supreme Court, on Jan. 20, 2009, the PUCT on behalf of all the respondents in the case including SPS, notified the court that all the respondents would wait until the court determines if it desired formal responses to LCEC's request for review before they filed individual responses.

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 16 to the consolidated financial statements.

18. 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 Kwh sold to customers from nuclear generation. Fuel expense includes the DOE fuel disposal assessments of approximately $13 million in 2008, 2007 and 2006, respectively. In total, NSP-Minnesota had paid approximately $386 million to the DOE through Dec. 31, 2008. 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 and dry cask facilities at both sites. The amount of spent fuel storage capacity currently authorized by the NRC and the MPUC will allow NSP-Minnesota to continue operation of its Prairie Island nuclear plant until the end of its current license terms in 2013 and 2014 and its Monticello nuclear plant until the end of its renewed operating license in 2030. Other 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.

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 2067, 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 and with its renewed operating license and certificate of need for spent fuel capacity to support 20 years of extended operation can operate until 2030. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are currently licensed to operate until 2013 and 2014, respectively. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC on Sept. 21, 2007. Construction of the Monticello dry-cask storage facility commenced on June 4, 2007. Construction of the facility is complete and 10 of the 30 canisters authorized have been filled and placed in the facility. Plant assessments and other work for the Prairie Island license renewal applications started in 2006. In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years until 2033 and 2034, respectively. The PIIC filed contentions in the NRC's license renewal proceeding in August 2008. The PIIC request was referred to an ASLB for review. The ASLB has granted the PIIC hearing request and has admitted seven of the 11 contentions filed. The resulting adjudicatory process and hearings are expected to add approximately eight months onto the NRC's standard 22 month review schedule (without hearings) resulting in the NRC not making a decision on whether or not to renew the Prairie Island operating licenses until late 2010. An application for a certificate of need to expand the spent fuel storage capacity at Prairie Island to support 20 additional years of operation was filed with the MPUC in May 2008. It is expected that the MPUC will act in late 2009 allowing the MPUC decision to be stayed during the 2010 session of the Minnesota legislature before going into effect.

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 study update submitted in October

2008 for the 2009 accrual. 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.

At Dec. 31, 2008, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning expense of $1.3 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.

	2008	2007
	(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 2008 and 2007 dollars (3.61 percent per year)	189,012	123,761
Estimated decommissioning cost obligation in current dollars	1,872,762	1,807,511
Effect of escalating costs to payment date (3.61 percent per year)	1,254,064	1,319,315
Estimated future decommissioning costs (undiscounted)	3,126,826	3,126,826
Effect of discounting obligation (using risk-free interest rate)	(1,847,526)	(1,502,030)
Discounted decommissioning cost obligation	1,279,300	1,624,796
Assets held in external decommissioning trust	1,075,294	1,317,564
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 204,006	$ 307,232

Decommissioning expenses recognized include the following components:

	2008	2007	2006
		(Thousands of Dollars)	
Annual decommissioning cost expense reported as depreciation expense:			
Externally funded	$43,239	$43,392	$48,069
Internally funded (including interest costs)	(819)	(759)	(5,046)
Net decommissioning expense recorded	$42,420	$42,633	$43,023

Reductions to expense for internally-funded portions in 2008, 2007 and 2006 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. The change in estimated decommission obligations was calculated using a cost estimate for Monticello assuming a 60-year operating life.

19. 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	2008	2007
		(Thousands of Dollars)		
Regulatory Assets				
Current regulatory asset — Unrecovered fuel costs	1	Less than one year	$ 32,843	$ 73,415
Pension and employee benefit obligations	12	Various	$1,212,542	$ 387,127
Net AROs[a]	1,17	Plant lives	299,294	39,891
AFDC recorded in plant[b]	1	Plant lives	220,354	189,698
Contract valuation adjustments[c]	14	Term of related contract	150,723	106,649
Conservation programs[b]		Various	117,188	119,839
Environmental costs	16,17	Generally four to six years once actual expenditures are incurred	75,880	55,038
Losses on reacquired debt	1	Term of related debt	66,268	73,002
Renewable resource costs		One to two years	55,868	51,785
Nuclear outage costs	16	Generally 18-24 months	40,690	—
Purchased power contracts costs	14	Term of related contract	20,716	—
Unrecovered natural gas costs	1	One to two years	14,657	22,505
State commission accounting adjustments[b]		Various	13,148	13,828
Rate case costs	1	Various	12,085	9,630
MISO Day 2 costs	1	To be determined in future rate proceedings	11,783	12,035
Nuclear fuel storage		Four years	9,652	11,578
Nuclear decommissioning costs		To be determined in future rate proceedings	8,775	11,149
Other		Various	27,656	11,689
Total noncurrent regulatory assets			$2,357,279	$1,115,443
Regulatory Liabilities				
Current regulatory liability — Overrecovered fuel costs[d]			$ 134,212	$ 34,451
Plant removal costs	1,17		$ 925,472	$ 906,996
Contract valuation adjustments[c]	14		124,676	108,533
Investment tax credit deferrals			68,313	72,686
Deferred income tax adjustments	1		42,619	59,282
Nuclear outage costs collected in advance from customers			13,678	—
Gain on sale of emission allowances	1		8,153	21,334
Interest on income tax refunds			1,736	3,472
Pension and employee benefit obligations	12		—	205,133
Other			9,949	12,551
Total noncurrent regulatory liabilities			$1,194,596	$1,389,987

(a) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.
(b) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.
(c) Includes the fair value of certain long-term purchased power agreements used to meet energy capacity requirements.
(d) Included in other current liabilities of $331,419 and $268,720 at Dec. 31, 2008 and 2007, respectively, in the consolidated balance sheets.

20. 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.
- 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	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
			(Thousands of Dollars)		
2008					
Operating revenues from external customers	$8,682,993	$2,442,988	$ 77,175	$ —	$11,203,156
Intersegment revenues	973	6,793	—	(7,766)	—
Total revenues	$8,683,966	$2,449,781	$ 77,175	$ (7,766)	$11,203,156
Depreciation and amortization	$ 715,695	$ 99,306	$ 13,378	$ —	$ 828,379
Interest charges and financing costs	352,083	45,819	131,371	(15,392)	513,881
Income tax expense (benefit)	345,543	73,647	(80,504)	—	338,686
Income (loss) from continuing operations	$ 552,300	$ 129,298	$ 27,346	$(63,224)	$ 645,720
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	$ 695,571	$ 96,323	$ 13,837	$ —	$ 805,731
Interest charges and financing costs	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	$ 695,321	$ 91,965	$ 15,612	$ —	$ 802,898
Interest charges and financing costs	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

21. Summarized Quarterly Financial Data (Unaudited)

Due to the seasonality of Xcel Energy's electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results. Summarized quarterly unaudited financial data is as follows:

	Quarter Ended			
	March 31, 2008	June 30, 2008	Sept. 30, 2008	Dec. 31, 2008
	(Thousands of Dollars, except per share amounts)			
Operating revenues	$3,028,388	$2,615,515	$2,851,680	$2,707,573
Operating income	330,118	259,836	447,994	352,843
Income from continuing operations	153,994	105,473	222,695	163,558
Discontinued operations — income (loss)	(877)	99	94	518
Net income	153,117	105,572	222,789	164,076
Earnings available to common shareholders	152,057	104,512	221,729	163,015
Earnings per share total — basic	$ 0.35	$ 0.24	$ 0.51	$ 0.36
Earnings per share total — diluted	0.35	0.24	0.51	0.36

	Quarter Ended			
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007
	(Thousands of Dollars, except per share amounts)			
Operating revenues	$ 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 (loss)	1,197	1,082	97	(927)
Net income	119,711	68,777	254,817	134,042
Earnings available to 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

22. Revision of Financial Statements

During preparation of the Xcel Energy's Annual Report on Form 10-K for the year ended December 31, 2008, it was determined that the investment in WYCO should have been reported as cash used in investing activities versus cash provided of $29.7 million as previously reported in the consolidated statement of cash flows for the year ended Dec. 31, 2007. In addition, the change in other noncurrent assets should have reflected cash provided of $3.3 million versus an outflow of $56.1 million. Net cash provided by operating activities was previously reported as $1,572 million and revised to $1,632 million. Net cash used in financing activities was previously reported as $2,022 million and revised to $2,082 million.

Xcel Energy determined that this revision was not material to its previously issued financial statements. As such, in accordance with the provisions of SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*, Xcel Energy reflected the revision in this Annual Report on Form 10-K.

Item 9 — Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

During 2007 and 2008, 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, 2008, 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 were 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, 2008 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 2009 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 2009 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 2009 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 2009 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 2009 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, 2008.
   Reports of Independent Registered Public Accounting Firm — For the years ended Dec. 31, 2008, 2007 and 2006.
   Consolidated Statements of Income — For the three years ended Dec. 31, 2008, 2007 and 2006.
   Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2008, 2007 and 2006.
   Consolidated Balance Sheets — As of Dec. 31, 2008 and 2007.
2. Schedule I — Condensed Financial Information of Registrant.
   Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2008, 2007 and 2006.
3. Exhibits

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* Indicates incorporation by reference

\+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

Xcel Energy

3.01* Restated Articles of Incorporation of Xcel Energy, as amended on May 21, 2008. (Exhibit 3.01 to Form 10-Q for the quarter ended June 30, 2008 (file no. 001-03034)).
3.02* Restated By-Laws of Xcel Energy (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).

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* 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).
4.03* 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).
4.04+* Form of Stock Option Agreement Dated Aug. 5, 2005 (Exhibit 4.04 to Form S-8 (file no. 333-127217) dated Aug. 5, 2005).
4.05+* Form of Restricted Stock Agreement Dated Aug. 5, 2005 (Exhibit 4.08 to Form S-8 (file no. 333-127217) dated Aug. 5, 2005).
4.06* 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).
4.07* $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).
4.08* 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).
4.09* 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).
4.10* Junior Subordinated Indenture, dated as of Jan.1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.11* Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, National Association, as trustee (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.12* Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).

NSP-Minnesota

4.13* 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, dated as follows:
4.14* Oct. 1, 1992 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Oct. 13, 1992).
4.15* April 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 30, 1993).
4.16* Dec. 1, 1993 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 7, 1993).
4.17* June 1, 1995 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995).
4.18* March 1, 1998 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998).
4.19* May 1, 1999 (Exhibit 4.49 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.20* June 1, 2000 (Exhibit 4.50 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.21* 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).
4.22* 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).
4.23* 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).

4.24* 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).

4.25* 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. 000-31387) dated Sept. 30, 2002).

4.26* 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. 000-31387) dated Sept. 30, 2002).

4.27* 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. 000-31387) dated July 8, 2002).

4.28* 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).

4.29* 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).

4.30* 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. (Exhibit 4.73 to Form 10-K (file no. 001-03034) for the year ended Dec. 31, 2003)

4.31* 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, (file no. 000-31387) dated July 14, 2005).

4.32* 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, (file no. 000-31387) dated May 18, 2006).

4.33* $500,000,000 Credit Agreement dated Dec. 14, 2006 between NSP-Minnesota and various lenders (Exhibit 99.02 to Form 8-K of Xcel Energy (file no. 001-3034) dated Dec. 14, 2006).

4.34* 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).

4.35* Supplemental Indenture dated March 1, 2008 between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated March 11, 2008.

NSP-Wisconsin

4.36* Supplemental and Restated Trust Indenture, dated March 1, 1991. (Exhibit 4.01 to Registration Statement 33-39831).

4.37* 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).

4.38* Supplemental Trust Indenture, dated Dec. 1, 1996. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).

4.39* 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).

4.40* 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).

4.41* Supplemental Trust Indenture dated as of Sept. 1, 2008 between Northern States Power Co. (a Wisconsin corporation) and U.S. Bank NA, as successor Trustee, creating $200,000,000 principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of Northern States Power Company, a Wisconsin corporation, dated Sept. 3, 2008 (file no. 001-03140)).

PSCo

4.42* 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)).

4.43* 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 (001-03280)	4.03
Jan. 1, 1994	10-K, 1993	4(b)(3)	Sept. 1, 2002	8-K, Sept. 18, 2002 (001-03280)	4.01
Sept. 2, 1994	8-K, September 1994	4(b)	Sept. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	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 (001-03280)	4(b)(3)	April 1, 2003	10-Q May 15, 2003 (001-03280)	4.02
Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)	May 1, 2003	S-4, June 11, 2003 (333-106011)	4.94
April 1, 1998	10-Q, March 31,1998 (001-03280)	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

4.44* 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).

4.45* 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).

4.46* $700,000,000 Credit Agreement dated Dec. 14, 2006 between PSCo and various lenders (Exhibit 99.03 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 14, 2006).

4.47* 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 001-03280) dated Aug. 14, 2007).

4.48* Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust National Association, as successor Trustee, creating $300,000,000 principal amount of 5.80% First Mortgage Bonds, Series No. 18 due 2018 and $300,000,000 principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of Public Service Company of Colorado dated Aug. 6, 2008 (file no. 001-03280)).

SPS

4.49* 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).

4.50* 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).

4.51* 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).

4.52* 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).

4.53* 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).

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

4.55* $250,000,000 Credit Agreement dated Dec. 14, 2006 between SPS and various lenders (Exhibit 99.04 to Form 8-K of Xcel Energy (file no. 001-03034) dated Dec. 14, 2006).

4.56* Supplemental Trust Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, N.A., as successor Trustee, creating $250,000,000 principal amount of Series G Senior Notes, 8.75% due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789)).

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+ Xcel Energy Inc. Non-Qualified Pension Plan (2009 Restatement)

10.03*+ Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to Form 10-Q of Xcel Energy (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+ Xcel Energy Senior Executive Severance Policy (2009 Amendment and Restatement)

10.06+ Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated Jan. 1, 2009.

10.07+ Xcel Energy Nonqualified Deferred Compensation Plan (2009 Restatement)

10.08+ Xcel Energy Non-employee Directors' Deferred Compensation Plan as amended and restated Jan. 1, 2009.

10.09* 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).

10.10*+ 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).

10.11*+ 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).

10.12*+ 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).

10.13*+ 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).

10.14*+ 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).

10.15*+ Xcel Energy Omnibus 2005 Incentive Plan (Appendix B to Schedule 14A, Definitive Proxy Statement dated April 11, 2005).

10.16*+ Xcel Energy Executive Annual Incentive Award Plan (Appendix C to Schedule 14A, Definitive Proxy Statement dated April 11, 2005)

10.17+ Xcel Energy Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009.

10.18* 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).

10.19*+ 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).

10.20*+ 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).

10.21+ First Amendment to the Xcel Energy Inc. Executive Annual Incentive Award Plan effective as of Jan. 1, 2009.

10.22+ First Amendment to Xcel Energy Inc. Omnibus Incentive Plan effective as of Jan. 1, 2009.

NSP-Minnesota

10.23* 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).

10.24* 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).
10.25* 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).
10.26* 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).
10.27* 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).
10.28* 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).
10.29* 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).
10.30* 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).
10.31* 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).
10.32* 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).
10.33* 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

10.34* 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

10.35* 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 10I(1)).
10.36* 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 10I(2)).
10.37* Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.38* 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

10.39* 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).
10.40* 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)).
10.41* 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)).
10.42* 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)).
10.43* 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 10I).
10.44* 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

(amounts in thousands of dollars)

	Year ended Dec. 31,		
	2008	2007	2006
Income			
Equity in income of subsidiaries	$708,943	$640,140	$625,298
Total income	708,943	640,140	625,298
Expenses and other deductions			
Operating expenses	10,481	7,630	9,143
Other income	(6,327)	(5,556)	(8,980)
Interest charges and financing costs	114,341	118,017	107,778
Total expenses and other deductions	118,495	120,091	107,941
Income from continuing operations before taxes	590,448	520,049	517,357
Income tax benefit	(55,272)	(55,850)	(51,324)
Income from continuing operations	645,720	575,899	568,681
Income (loss) from discontinued operations, net of tax	(166)	1,449	3,073
Net income	645,554	577,348	571,754
Preferred dividend requirements	4,241	4,241	4,241
Earnings available to common shareholders	$641,313	$573,107	$567,513

Statements of Cash Flows

(amounts in thousands of dollars)

	Years Ended Dec. 31		
	2008	2007	2006
Operating activities			
Net cash provided by operating activities	$ 455,388	$ 566,688	$ 634,128
Investing activities			
Return of capital from subsidiaries	64,353	129,551	201,185
Capital contributions to subsidiaries	(630,427)	(559,266)	(576,600)
Net cash used in investing activities	(566,074)	(429,715)	(375,415)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	125,000	238,877	(211,716)
Proceeds from issuance of long-term debt	386,518	—	294,830
Repayment of long-term debt	(322,803)	—	—
Proceeds from issuance of common stock	352,871	10,539	16,275
Early participation payment on debt exchange	—	(4,859)	—
Dividends paid	(382,283)	(378,892)	(358,746)
Net cash used in (provided by) financing activities	159,303	(134,335)	(259,357)
Net increase (decrease) in cash and cash equivalents	48,617	2,638	(644)
Cash and cash equivalents at beginning of year	3,161	523	1,167
Cash and cash equivalents at end of year	$ 51,778	$ 3,161	$ 523

CONDENSED FINANCIAL STATEMENTS OF XCEL ENERGY INC.

Balance Sheets

(amounts in thousands of dollars)

	2008	2007
Assets		
Cash and cash equivalents	$ 51,778	$ 3,161
Accounts receivable from subsidiaries	275,077	187,522
Other current assets	6,573	29,313
Total current assets	333,428	219,996
Investment in subsidiaries	8,465,003	7,790,574
Other assets	61,675	40,460
Noncurrent assets related to discontinued operations	15,914	16,926
Total other assets	8,542,592	7,847,960
Total assets	$8,876,020	$8,067,956
Liabilities and Equity		
Dividends payable	$ 108,838	$ 99,681
Short-term debt	350,250	602,962
Other current liabilities	23,493	49,396
Current liabilities related to discontinued operations	—	535
Total current liabilities	482,581	752,574
Other liabilities	25,440	11,786
Long-term debt	1,299,278	897,614
Preferred stockholder's equity	104,980	104,980
Common stockholder's equity	6,963,741	6,301,002
Total capitalization	8,367,999	7,303,596
Total liabilities and equity	$8,876,020	$8,067,956

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 $630 million, $694 million, and $759 million in the three years ended Dec. 31, 2008, 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, 2008, 2007 and 2006

(amounts in 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:					
2008	$49,401	$63,407	$16,468	$65,037	$64,239
2007	36,689	57,434	18,052	62,774	49,401
2006	39,798	56,919	16,022	76,050	36,689

(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.

Feb. 27, 2009

By: /s/ BENJAMIN G.S. FOWKE III

Benjamin G.S. Fowke III
Executive 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 on Feb. 27, 2009.

	/s/ RICHARD C. KELLY RICHARD C. KELLY	Chairman, President and Chief Executive Officer (Principal Executive Officer)
	/s/ TERESA S. MADDEN TERESA S. MADDEN	Vice President and Controller (Principal Accounting Officer)
	/s/ BENJAMIN G.S. FOWKE III BENJAMIN G.S. FOWKE III	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
*	C. CONEY BURGESS	Director
*	FREDRIC W. CORRIGAN	Director
*	RICHARD K. DAVIS	Director
*	ROGER R. HEMMINGHAUS	Director
*	DOUGLAS W. LEATHERDALE	Director
*	ALBERT F. MORENO	Director
*	MARGARET R. PRESKA	Director
*	A. PATRICIA SAMPSON	Director
*	RICHARD H. TRULY	Director
*	DAVID A. WESTERLUND	Director
*	TIMOTHY V. WOLF	Director
*	/s/ TERESA S. MADDEN TERESA S. MADDEN Attorney-in-Fact	

Shareholder **Information**

HEADQUARTERS
414 Nicollet Mall, Minneapolis, Minnesota 55401

INTERNET ADDRESS
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 xcelenergy.com. Click on Investor Information.

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL
Common stock is listed on the New York Stock Exchange (NYSE) under the ticker symbol XEL. The 7.6% Junior Subordinated Notes, Series due 2068 are listed on the NYSE under the ticker symbol XCJ. The NYSE lists some of Xcel Energy's preferred stock. In newspaper listings, it appears as XcelEngy.

INVESTOR RELATIONS
Internet address: 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: xcelenergy.com or contact Tara Heine, Assistant Corporate Secretary, at 612-215-5391, or e-mail tara.m.heine@xcelenergy.com.

CORPORATE GOVERNANCE
Xcel Energy has filed certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 or the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2008 that it has filed with the Securities and Exchange Commission. It has also filed with the New York Stock Exchange the CEO certification for 2008 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]
Chairman, 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]
CEO and Owner
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]
Chief Integration Officer
Miller Coors Brewing Company

Board Committees:
1. Audit
2. Governance, Compensation and Nominating
3. Finance
4. Nuclear, Environmental and Safety

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