Annual Report 2004

BUILDING *the* CORE

Xcel Energy

COMPANY OVERVIEW

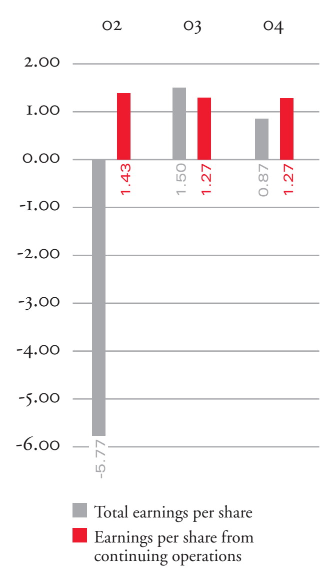
COMPANY DESCRIPTION Xcel Energy Inc. is a major U.S. electric and natural gas company, with annual revenues of $8 billion. Based in Minneapolis, Minn., Xcel Energy operates in 10 Western and Midwestern states. The company provides a comprehensive portfolio of energy-related products and services to 3.3 million electricity customers and 1.8 million natural gas customers. In terms of customers, Xcel Energy is the fourth-largest combination electric and natural gas company in the nation.

FINANCIAL HIGHLIGHTS

	2004	*2003*
Earnings per common share – diluted	**$ 0.87**	$ 1.50
Discontinued operations	**$ (0.40)**	$ 0.23
Earnings per common share – diluted before discontinued operations	**$ 1.27**	$ 1.27
Dividends annualized	**$ 0.83**	$ 0.75
Stock price (close)	**$ 18.20**	$ 16.98
Assets (millions)	**$20,305**	$20,205
Book value per common share	**$ 12.99**	$ 12.95

Some of the sections in this annual report, including the letter to shareholders on page 2, contain forward-looking statements. For a discussion of factors that could affect operating results, please see the Management's Discussion and Analysis on page 16.

XCEL ENERGY EARNINGS PER SHARE
dollars per share (diluted)



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ABOUT THE PHOTOGRAPHY

Depicting images of tubes, spools and other circular items, this year's photography reflects our strategy for success. Expressing dynamism, motion and progress, each image visually reinforces our commitment to focusing on and growing our core businesses.

DEAR SHAREHOLDERS

2004 was a good year for Xcel Energy. We focused our full attention on our core electric and natural gas businesses to achieve two top priorities:
– growing the business to build value for you; and
– meeting the energy needs of our customers.

Our accomplishments in 2004 and our plans for the future demonstrate that we are determined to stay firmly focused on what we do best – generating and delivering safe, reliable energy – and achieve success solely as a regulated utility. We call that strategy Building the Core, and its first full year of execution produced good results.

THE YEAR IN REVIEW

Xcel Energy met its financial expectations in 2004, based on our initial earnings guidance of $1.15 to $1.25 per share. Earnings from continuing operations were $527 million, or $1.27 per share on a diluted basis, compared with $526 million, or $1.27 per share, in 2003.

Total earnings were $356 million, or 87 cents per share, compared with $622 million, or $1.50 per share, in 2003. Those results include the impact of discontinued operations, which were losses of $171 million, or 40 cents per share, in 2004. The losses include an after-tax impairment charge of $143 million, or 34 cents per share, related to the planned sale of Seren Innovations, Inc., our broadband communications company. The results in 2003 included tax benefits related to Xcel Energy's write-off of its investment in NRG Energy, Inc., which was divested at year-end 2003.

Our earnings guidance for 2005 is in the range of $1.18 to $1.28 per share from continuing operations. Long term, our goal is to grow earnings per share 2 percent to 4 percent annually and deliver a total return of 7 percent to 9 percent.

Strong financial prospects mid-year allowed us to increase your annual dividend rate by 8 cents per share. This year, the board will evaluate our dividend policy again, taking into consideration:
– our ability to grow earnings;
– our plans to invest significant capital in the business;
– our goal to improve our credit ratings; and
– our desire to provide you with an appropriate return on your investment.

PICTURED ABOVE Wayne H. Brunetti, Chairman and Chief Executive Officer (right), and Richard C. Kelly, President and Chief Operating Officer (left)

Our objective is to deliver financial results that lead to annual dividend increases at a rate consistent with our long-term earnings growth rate objective of 2 percent to 4 percent.

We also discontinued several businesses in 2004 that were not strong contributors to our core. They included Planergy International Inc., an energy management company; our e prime inc. natural gas trading operations; and effectively all assets of Xcel Energy International Inc. We announced that Seren Innovations, Inc., is for sale and, in early 2005, we completed the sale of Cheyenne Light, Fuel and Power Company.

Selling assets was just one element in delivering on our strategy, which we accomplish by relying on two value drivers:
– investing in our system; and
– earning our authorized return.

INVESTING IN OUR SYSTEM

With energy demand growing, we are making significant investments in our generation, transmission and distribution systems that should prove to be our most robust value driver. One of the biggest efforts is our plan to build a 750-megawatt generating unit called Comanche 3 at our Comanche coal-fired facility near Pueblo, Colo. We achieved a major milestone in the Comanche 3 project at the end of 2004, when the Colorado Public Utilities Commission approved it as part of our least-cost resource plan. We are pursuing other approvals and permits before construction can begin.

The least-cost resource plan outlined options to meet the need for 3,600 megawatts in the state by 2013, while strongly considering Colorado's environmental needs. All of Comanche's generating units will be fitted with advanced emission-reduction equipment, including Comanche 3. Although we will more than double the facility's current 660-megawatt capacity, overall sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from Comanche will decline. We also will significantly expand our energy conservation programs in Colorado, accelerate a study of additional renewable resources, explore innovative technologies to reduce greenhouse gas emissions and account for potential carbon reduction regulation when we do our resource planning in the future.

Xcel Energy will own 500 megawatts of Comanche 3, which could begin producing electricity by 2010. The total cost for the 750-megawatt power plant, including all required transmission lines, is an estimated $1.35 billion.

Energy demand is growing in Minnesota, too, where we filed a similar resource plan to meet a projected 3,100-megawatt demand for new generation by 2019. As in

Colorado, the Minnesota plan balances cost, reliability and environmental protection, and includes the possibility of new construction and significant new environmental goals. The Minnesota Public Utilities Commission should address the plan this year.

2004 saw other projects in full swing – or successfully completed – across our service territory.

- Construction has begun on a $1 billion emission-reduction project to convert two coal-fired power plants in Minnesota to natural gas and refurbish a third with advanced emission-control equipment.
- Three new natural-gas-fired peaking units, at a cost of $125 million, should be on line this summer, a time of high electric demand, at our Blue Lake facility in Minnesota and our Angus Anson plant in South Dakota.
- At our Prairie Island nuclear plant, we completed a $132 million project to replace steam generators on unit 1, which will enable the plant to continue its history of safe, reliable operation. In fact, the operational excellence of both the Prairie Island and Monticello nuclear plants prompted our decision in 2004 to take the necessary steps to renew their operating licenses with the Nuclear Regulatory Commission (NRC) for up to 20 years.

Getting electricity to market – and ensuring reliability for customers – drives our investment in new and upgraded transmission and distribution lines.

- In the south, we completed a $154 million, 345-kilovolt transmission line project from Amarillo, Texas, to Lamar, Colo., which strengthens our entire transmission network, enhancing reliability and improving our ability to deliver 162 megawatts of wind power from the Colorado Green wind farm near Lamar. The project, which includes significant substation improvements, also creates an additional tie linking the nation's eastern and western electrical grids.
- In Minnesota, we have a $160 million project under way to upgrade the region's transmission system and help deliver wind power from the Buffalo Ridge area of the state.
- We invested $440 million in improvements to our distribution system in 2004, and plan to invest approximately $430 million in additional improvements in 2005.

EARNING OUR AUTHORIZED RETURN

With significant investment in our generation, transmission and distribution systems, we must recover and earn a return on the cost of that investment, which explains the importance of our second value driver: earning our authorized return.

Although not as visible as a new power plant or transmission line, our work to ensure a regulatory framework that allows us to earn a return sufficient to retain and attract capital to the business is equally important. To do this, we make certain the company has rates and a regulatory process in place that will allow it to recover its costs of providing service. Several regulatory filings were under way in 2004 to change rates, and we plan to file for additional rate increases in 2005.

Our Building the Core strategy served us well in 2004 and should create even greater benefits going forward as projects are completed. It's a simple yet powerful plan that addresses our most important priorities.

ENVIRONMENTAL PROTECTION

With all its activity, 2004 proved to be an energizing and optimistic year. Satisfying the need for reliable energy is rewarding work – but also a balancing act. We balance our obligation to customers with our lasting commitment to protect the environment, and we do it well.

Xcel Energy is a leading utility in environmental protection. The foundation of our effort is compliance – a major undertaking in itself, but we voluntarily go above and beyond compliance levels, provided the investment is prudent and we earn a return on it. Few utilities are as proactive – with the results to prove it.

- The voluntary emission-reduction programs we've launched in Colorado and Minnesota are among the largest in the nation. In its second year of operation, the Colorado effort again met its annual goal of reducing SO_2 emissions by 22,000 tons and NO_X emissions by 2,500 tons.
- In 2004, we announced our carbon management plan concerning emissions of carbon dioxide (CO_2), a greenhouse gas. By 2009, the company will reduce total CO_2 emissions by a cumulative total of 12 million tons from 2003 levels. By 2012, Xcel Energy will reduce CO_2 intensity, which refers to pounds of CO_2 emitted per megawatt-hour, by 7 percent from 2003 levels.
- Even with electric generation growing, we were able to decrease emissions, with generation increasing 12 percent since 1997, while the rate of SO_2 emissions decreased by 25 percent and the rate of NO_X emissions decreased by 20 percent.
- We are the nation's second-largest retail provider of wind energy, with 884 megawatts of wind energy in our generating portfolio at the end of 2004, and plans to add another 712 megawatts by the end of 2005.
- Our Windsource program is the largest voluntary wind energy program in the United States, with 38,236 customers at the end of 2004 in Colorado, Minnesota and New Mexico.

For Xcel Energy, environmental protection is a core value that shapes every decision we make about satisfying the energy needs of our customers.

FINAL THOUGHTS

Looking back on 2004, we realize some things haven't changed.

Congress still needs to pass comprehensive energy legislation and an environmental policy that will give utilities like Xcel Energy more certainty about regulations and the flexibility to meet those requirements. We told you that last year and we'll say it again.

Employees continue to impress us with their safe work ethic, commitment to customers and willingness to help others – whether those people are community members, Florida hurricane victims, our troops overseas or tsunami survivors. Our optimism for the future is based in large part on the fact that we have excellent employees.

Finally, we remain grateful for the trust you continue to have in Xcel Energy. As you know by now, our strategy is simple, straightforward and designed to build value for you. Our promise is to continue to work hard to meet that goal.

We'd like to close by thanking W. Thomas Stephens and David A. Christensen for their years of service on our board of directors. Tom, who resigned in October 2004, had been a member of the Xcel Energy board and those of predecessor companies since 1989. Dave, who will retire in May, has been a member of the Xcel Energy board and a predecessor company since 1976.

Sincerely,

Wayne H. Brunetti
Chairman and Chief Executive Officer

Richard C. Kelly
President and Chief Operating Officer

BUILDING *the* CORE

To achieve long-term success, Xcel Energy is relying on its core businesses to build value for shareholders and meet the energy needs of its customers. Fundamental to that effort, which we call Building the Core, are excellent operations, environmental protection, customer service and community care. In each category, we achieved good results in 2004.

EXCELLENT OPERATIONS

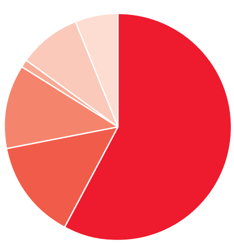
As always, Xcel Energy's power plants were strong performers. Among our coal-fired facilities, the Harrington Station in Texas set a new generating record and our Sherco plant in Minnesota achieved its best reliability performance since 1996, with unit 3 doing especially well.

Our Prairie Island and Monticello nuclear plants maintained the NRC's highest rating for operational excellence and are in a category reserved for facilities that have earned the NRC's highest level of confidence. Both plants devoted significant effort in 2004 to successfully meet the NRC's new security requirements.

In addition, Monticello set a new generating record, and both plants received a Governor's Safety Award from the Minnesota Safety Council for excellence in workplace safety and health.

Safety results are a good indication of operational excellence, and Xcel Energy achieved solid scores in 2004. Overall, we met our corporate safety goal and each business unit met or exceeded its goals. Those results reflect many safety success stories across the company. In our customer and field operations area, for example, more than 1,000 employees have worked more than 10 years without a safety mishap. Employees at our Campion High Pressure Gas Service Center in Colorado have worked more than 25 years without a lost-workday incident. Several power plants have operated two or three years without a safety incident.

XCEL ENERGY PORTFOLIO OF ENERGY SOURCES



- Coal 5
- Nuclear 14
- Gas & Oil 12
- Rene ables* 1
- Purchases 9
- Manitoba wydro Purchases 6

* Rene ables include ind, hydro and biomass.

ENVIRONMENTAL PROTECTION

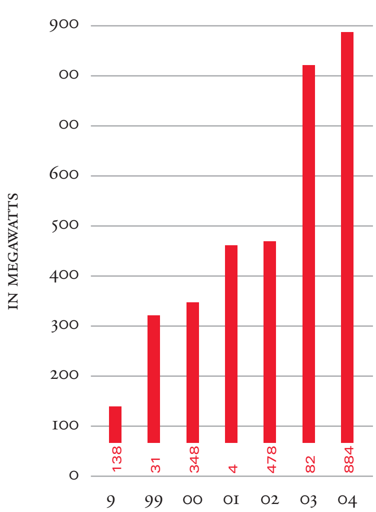
With our voluntary emission-reduction programs in Colorado and Minnesota, our large and growing renewable energy portfolio and our voluntary wind energy program, Xcel Energy is a leader in environmental protection. But beyond the high-profile projects, a day-to-day focus on environmental compliance and many other smaller efforts contribute greatly to our success.

Take the French Island plant in La Crosse, Wis., for example, which takes municipal solid waste from La Crosse County and other sources, turns it into refuse-derived fuel and then burns it with waste wood to produce electricity. For the second year running, French Island finished the year with no environmental exceedances, a significant achievement. Those results follow on the heels of an air-quality control system replacement project in which employees worked with county, state and federal officials to come up with the best solutions to produce power, protect the environment, deal with the county's waste and make renewable technologies work.

In 2004, we celebrated the fact that over the last 15 years 189 peregrine falcons have fledged from nest boxes on the stacks of Xcel Energy power plants. Working with the Raptor Resource Project, we take pride in the fact that the peregrine is no longer listed as an endangered species. And peregrines aren't the only birds of interest. We work actively to promote habitats for osprey, eagles, blue birds, owls, hawks and kestrels. Other creatures find sanctuary in the areas around our power plants, which often function as nature preserves.

To use resources wisely in our daily operations, Xcel Energy recycles coal ash, the primary byproduct of electric generation, into concrete products, roadbed material and soil-stabilization products. We also use wastewater for cooling and other purposes at our power plants. In addition to reusing our own water, we purchase and re-treat municipal wastewater from nearby communities.

The company strongly supports the development of renewable energy technologies through our Renewable Development Fund, which awards grants to develop projects and conduct research. In 2004, we recommended to the Minnesota Public Utilities Commission that 28 projects receive a total of $26.5 million. We also operate a Renewable Energy Trust in Colorado for customers interested in funding renewable energy projects at nonprofit organizations and K-12 schools.



XCEL ENERGY WIND GENERATION

With 884 megawatts of wind energy in its portfolio at the end of 2004, Xcel Energy is the second-largest retail provider of wind energy in the nation.

Finally, one of our most significant environmental efforts is working with customers to conserve energy and manage its use. In 2004, we helped Xcel Energy customers conserve almost 340 gigawatt-hours of electricity, the equivalent amount of electricity used by 45,000 homes in a year. Our natural gas customers conserved the equivalent amount of natural gas used in 7,000 homes annually.

CUSTOMER SERVICE

The reliability of our electrical system is a good measure of customer satisfaction. In 2004, we increased system capacity, addressed pockets of poor performance and added employees in some areas – for outstanding results. Based on the industry measure of total outage minutes experienced by our customers, we improved our Colorado reliability performance by 33 percent over last year and our Minnesota performance by 20 percent.

We carefully track our contacts with customers, believing that every interaction a customer has with Xcel Energy should be positive. At the end of 2004, Xcel Energy ranked in the top 10 percent for customer satisfaction among residential customers, compared with other utilities.

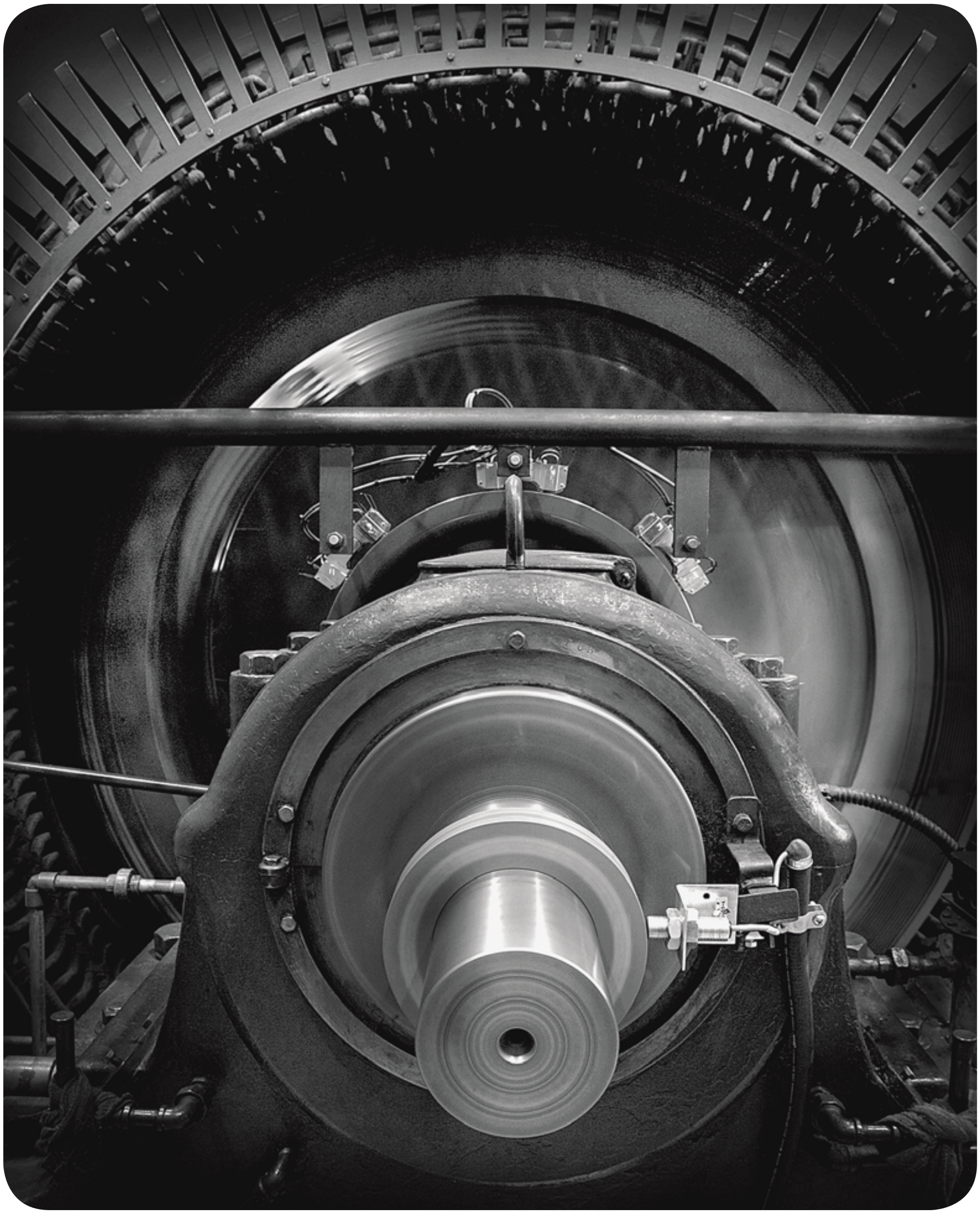
We also rely on improved technology in our customer service effort. In 2004, we launched a new billing and customer service system that should enhance efficiency. Our natural gas customers will benefit from an upgraded central computer system that is able to monitor in real time 293 locations, including meter, regulator and compressor stations as well as natural gas plants.

Xcel Energy crews care about customers – no matter where those customers reside. About 250 Xcel Energy employees from across our 10-state service territory traveled to Florida and Alabama to help in the restoration efforts following Hurricanes Frances, Ivan and Jeanne. Electric utilities maintain mutual-aid agreements for responses to storm-caused destruction. Progress Energy, Florida Power and Light, and Alabama Power reimbursed Xcel Energy for all costs associated with the storm cleanup.

COMMUNITY CARE

Because Xcel Energy is only as strong as the communities it serves, the company devotes significant funding and effort to community care. In 2004, the Xcel Energy Foundation granted $8 million in corporate funding to charitable organizations. The foundation targets its grants toward education, arts and cultural activities, and building stronger communities.

SIGNIFICANT FUNDING AND EFFORT TO COMMUNITY CARE



Employee and retiree volunteerism is another component of the company's community care effort. In 2004, we commemorated the 15th anniversary of the Kitchen Appliance Marking Program. More than 1,530 visually impaired customers have benefited from the free service, in which Xcel Energy retiree volunteers apply raised markings to the dials of appliances to promote safe and efficient use.

In 2004, Xcel Energy conducted its most successful United Way campaign in the company's history. Employees and retirees pledged more than $2 million, an 18-percent increase over 2003 and well above the goal of $1.8 million. The company matches employee and retiree contributions, for a total of more than $4 million going to United Way organizations across our service territory.

To contribute to the financial health of our communities, we support a variety of economic development efforts. In North Dakota, we provided seed money to the North Dakota State University Research and Technology Park in Fargo, hoping to attract high-tech companies to the area. In early 2005, the park included six companies, providing about 400 jobs and contributing 3,150 kilowatts of demand to Xcel Energy's system.

In a unique community partnership, we completed the Platte substation relocation project in the summer of 2004. Working with the city of Denver, Xcel Energy moved a substation from land along the Platte River to make room for a recreational area on a site commonly known as the birthplace of Denver. We agreed to trade land with the city, which contributed to the cost of moving the substation. In addition, Xcel Energy and other partners worked together to creatively landscape the site of the newly relocated substation.

Xcel Energy also is a strong supporter of women- and minority-owned businesses. In 2004, we spent more than $103 million through our supplier diversity program.

With strong commitments to excellent operations, environmental protection, customer service and community, Xcel Energy is in a good position to achieve its Building the Core strategy. These commitments will carry us forward as we build value for you.

BUSINESS SEGMENTS AND ORGANIZATIONAL OVERVIEW

Xcel Energy Inc. (Xcel Energy), a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). In 2004, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 10 states. These utility subsidiaries are Northern States Power Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo) and Southwestern Public Service Co. (SPS). These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. Along with WestGas InterState Inc. (WGI), an interstate natural gas pipeline, these companies comprise our continuing regulated utility operations. Discontinued utility operations include the activity of Viking Gas Transmission Co. (Viking), an interstate natural gas pipeline company that was sold in January 2003; Black Mountain Gas Co. (BMG), a regulated natural gas and propane distribution company that was sold in October 2003; and Cheyenne Light, Fuel and Power Co. (Cheyenne), a regulated electric and natural gas utility that was sold in January 2005.

Xcel Energy's nonregulated subsidiaries in continuing operations include Utility Engineering Corp. (engineering, construction and design) and Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits). During 2003, Planergy International, Inc. (energy management solutions) closed and began selling a majority of its business operations with final dissolution occurring in 2004. On March 2, 2005, Xcel Energy agreed to sell its non-regulated subsidiary UE to Zachry Group, Inc. Zachry agreed to acquire all of the outstanding shares of UE, including three UE subsidiaries: Precision Resource Co., a professional staffing company; Proto-Power Corp., an engineering and project management company dedicated to the nuclear power industry; and Universal Utility Services, LLC, a full-service industrial maintenance group. Quixx Corp., a subsidiary of UE that partners in cogeneration projects is not included in the transaction. Xcel Energy expects to record a small loss as a result of the transaction; however, the transaction is not expected to have a material effect on the financial condition of Xcel Energy. The transaction is subject to customary terms and conditions as to closing and is expected to be completed in April 2005.

During 2004, Xcel Energy's board of directors approved management's plan to pursue the sale of Seren Innovations, Inc. (Seren), a broadband telecommunications services company. During 2003, Xcel Energy also divested its ownership interest in NRG Energy, Inc. (NRG), an independent power producer. On May 14, 2003, NRG filed for bankruptcy to restructure its debt. As a result of the reorganization, Xcel Energy relinquished its ownership interest in NRG. During 2003, the board of directors of Xcel Energy also approved management's plan to exit businesses conducted by the nonregulated subsidiaries Xcel Energy International Inc. (Xcel Energy International), an international independent power producer, operating primarily in Argentina, and e prime inc. (e prime), a natural gas marketing and trading company. NRG, Xcel Energy International, e prime and Seren are presented as a component of discontinued operations.

See Note 3 to the Consolidated Financial Statements for further 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; structures that affect the speed and degree to which competition enters the electric and natural gas markets; the higher risk associated with Xcel Energy's nonregulated businesses compared with its regulated businesses; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; risks associated with the California power market; 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 Securities and Exchange Commission (SEC), including Exhibit 99.01 to Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2004.

MANAGEMENT'S STRATEGIC PLANS

The structure of the utility industry is continually changing, which is driven, in part, by the many different types of government regulation over the industry. Generally, the states in which a utility operates determine the rates that the utility charges its retail customers. The Federal Energy Regulatory Commission (FERC) establishes the rates that utilities charge for power sold at the wholesale level. The FERC also develops and administers various rules that govern how utilities operate. Utilities also face a wide range of environmental regulations from various government agencies, at both the state and federal level.

The mix of state and federal regulations result in numerous rules and regulations, which are not always consistent and are subject to continual change. Clearly, compliance with all of the regulatory requirements increases the complexity and uncertainty of our business.

In the last decade or so, the FERC and many states developed rules to encourage competition and deregulation of the utility sector. As a result of these regulatory changes, many utilities have taken steps to prepare for competition and the changing rules. These actions included:
– completion of mergers and acquisitions to increase economies of scale;
– efficiency improvements and cost cutting to avoid rate cases and improve competitive position;

– sales of power plants;
– use of purchase power contracts to meet growth in electric requirements; and
– development of nonregulated ventures.

On the federal level, the FERC is still very active in promoting wholesale competition. Wholesale operations account for approximately 16 percent of our revenue. FERC has authority to withhold market-based rates on wholesale sales in certain areas where a utility is determined to have "market power control." However, Xcel Energy believes that it will continue to have the ability to make sales under its market-based tariff.

As part of its agenda to encourage competition, the FERC has also been very active in promoting regional transmission organizations (RTOs). In the past, each individual utility controlled its transmission lines. Based on certain FERC initiatives, RTOs will control the operations of transmission lines for an entire region to ensure that all parties that want to sell power have access to the lines. We currently participate in the Midwest Independent Transmission System Operator, Inc. (MISO) and the Southwest Power Pool (SPP). We are supportive of RTO participation, provided that they offer benefits to our customers and we have clear cost-recovery mechanisms. In 2005, the MISO will begin its Day 2 operations. This will result in uncertainty, which may have a positive or negative impact on our wholesale margins.

However, at the state level, many states have stopped utility restructuring activity due to the failure of the California power markets, the collapse of the independent power producers and other factors.

For Xcel Energy, no significant retail regulatory restructuring has occurred or is expected to occur in any of the states in which we have major utility operations. In some parts of Texas, retail customers can choose their energy provider. However, due to legislation that extends through 2007, the panhandle of Texas, where we have utility operations, remains under traditional regulation. We believe that the panhandle will remain under traditional regulation after 2007.

Our retail operations represent approximately 82 percent of our revenues. Retail rates are set by state commissions and are intended to provide the utility the opportunity to earn an authorized return on equity. Whether the utility actually earns its authorized return on equity is dependent on many factors including the level of sales growth, changes in a company's cost structure, capital investment, interest rates and other items.

Until recently, we have avoided the need to file rate cases by experiencing relatively robust growth in our service territories as well as aggressively managing the costs of our business. Through two mergers, we have realized cost savings and operational efficiencies. These steps have helped us to avoid filing rate cases, but at the same time, we have made significant investments. While we will continue to look for ways to reduce costs, the opportunities are no longer large enough to further delay rate cases.

Our regulatory strategy is to ensure that we have the opportunity to earn our authorized return on equity in each state. We are currently not earning our authorized return on equity in the majority of the states where we have our regulated utility operations. As a result, we have begun or in the near-term will begin filing general rate increases in the majority of our jurisdictions as follows.
– In September 2004, we filed for an approximately $10 million natural gas rate increase in Minnesota. The request assumes an 11.5 percent return on equity. Interim rates, subject to refund, went into effect in December 2004 and we expect a decision this summer.
– Also in 2004, we filed for a $5 million transmission increase at FERC.
– In Wisconsin, we are required to file a rate case every other year. Therefore, NSP-Wisconsin will file a case during 2005.
– In Minnesota, we plan to file an electric rate case in the fourth quarter of this year with interim rates, subject to refund, effective in early 2006. We expect a final commission decision in late summer or early fall of 2006.
– Finally, we intend to file an electric rate case in Colorado in 2006, with rates expected to be in effect during 2007.

While recovery of costs cannot be assured, we are optimistic we will receive fair treatment. We believe that we have fair regulation as demonstrated by the successful agreement reached on projects like the metropolitan emissions reduction project (MERP) in Minnesota and the new construction of the Comanche 3 electric generating unit in Colorado. Our ability to maintain a constructive regulatory framework is a critical component of our strategy and ultimate success.

Though we remain open to all opportunities to increase shareholder value, our strategy is to invest in our core electric and natural gas businesses to meet the growing energy needs of our customers, while earning a fair return on our investments. We refer to our strategy as Building the Core. We have no plans or interest in deviating from our core business.

We see four critical factors to create incremental value for our shareholders and view these factors as building blocks. They are largely independent of each other, but taken together, they have the potential to create significant additional value.
– The first is service territory growth. With the strength and diversity of our service territory, growth provides a solid foundation year after year.
– The second driver is incremental investment in our core businesses. Certain incremental investment has already started at a modest level and will grow quickly in the coming years. Key projects include the MERP project and the Comanche 3 coal plant.
– The third driver is to increase the level of equity that we have invested in our operating companies. Additional equity will increase our financial strength, support a higher credit rating and add to earnings and cash flow. We will work with our regulators to gain support for this initiative.
– Lastly, we will strive to earn our regulated authorized returns, which will require filing for rate increases in our largest jurisdictions over the next few years.

Execution of our strategy will allow us to meet or exceed our financial objective of delivering an average total return of 7 percent to 9 percent per year. Our total return objective is based on our expectations of long-term earnings growth of 2 percent to 4 percent and a dividend yield of approximately 5 percent.

We have established a dividend policy that we believe is sustainable and contributes to a competitive total return for our shareholders. Our objective is to deliver the financial results that will enable our board of directors to grant annual dividend increases at a rate consistent with our long-term earnings growth rate.

As we look to 2005, we are focused on several challenges, in addition to the normal day-to-day operations of our utility business.

– We must prepare for operational uncertainty surrounding the implementation of various FERC initiatives, which could impact our short-term wholesale margins.
– We must manage our procurement efforts to attempt to mitigate the impact of rising fuel costs, which are passed on to our customers.
– We must continue to look for creative ways to offset rising health care and benefit costs, while we continue our efforts to improve reliability and customer service.
– While we believe we are well positioned for changing environmental rules and regulations based on the work we have done in the last few years on projects such as MERP, we plan to continue our aggressive efforts to improve our environmental performance.
– We need to obtain uncontested environmental permits for the new construction of the Comanche 3 coal plant.
– We expect to complete the sale of Seren.
– Finally, we will need to seek a Minnesota electric rate increase at the end of 2005. This case will be important as we move into 2006.

We believe that we have a solid and straightforward strategy and that, as we execute our plan, it will serve to increase shareholder value.

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 Notes. All note references refer to the Notes to Consolidated Financial Statements.

RESULTS OF OPERATIONS

Summary of Financial Results

The following table summarizes the earnings contributions of Xcel Energy's business segments on the basis of generally accepted accounting principles (GAAP). Continuing operations consist of the following:

– regulated utility subsidiaries, operating in the electric and natural gas segments; and
– several nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of the following:

– Seren, a nonregulated subsidiary, which was classified as held for sale in the third quarter of 2004 based on a decision to divest this investment;
– the regulated natural gas businesses Viking and BMG, which were sold in 2003;
– the regulated utility business of Cheyenne, which was sold in January 2005;
– NRG, which emerged from bankruptcy in late 2003, at which time Xcel Energy divested its ownership interest in NRG; and
– the nonregulated subsidiaries Xcel Energy International and e prime, which were classified as held for sale in late 2003 based on the decision to divest them.

Prior-year financial statements have been restated to conform to the current-year presentation and classification of certain operations as discontinued. See Note 3 to the Consolidated Financial Statements for a further discussion of discontinued operations.

Contribution to earnings (Millions of dollars)	***2004***	*2003*	*2002*
GAAP income (loss) by segment			
Regulated electric utility segment income – continuing operations	**$466.3**	$461.3	$ 484.9
Regulated natural gas utility segment income – continuing operations	**86.1**	94.1	88.2
Other utility results *(a)*	**6.0**	6.4	20.1
Total utility segment income – continuing operations	**558.4**	561.8	593.2
Other nonregulated results and holding company costs *(a)*	**(31.5)**	(36.0)	(41.8)
Total income – continuing operations	**526.9**	525.8	551.4
Regulated utility income (loss) – discontinued operations	**(9.0)**	26.8	13.8
NRG loss – discontinued operations	**–**	(251.4)	(3,444.1)
Other nonregulated income (loss) – discontinued operations *(b)*	**(161.9)**	321.2	660.9
Total income (loss) – discontinued operations	**(170.9)**	96.6	(2,769.4)
Total GAAP income (loss)	**$356.0**	$622.4	$(2,218.0)

Contribution to earnings per share	***2004***	*2003*	*2002*
GAAP earnings per share contribution by segment			
Regulated electric utility segment – continuing operations	**$1.10**	$1.10	$ 1.26
Regulated natural gas utility segment – continuing operations	**0.20**	0.22	0.23
Other utility results *(a)*	**0.02**	0.02	0.05
Total utility segment earnings per share – continuing operations	**1.32**	1.34	1.54
Other nonregulated results and holding company costs *(a)*	**(0.05)**	(0.07)	(0.11)
Total earnings per share – continuing operations	**1.27**	1.27	1.43
Regulated utility earnings (loss) – discontinued operations	**(0.02)**	0.06	0.03
NRG loss – discontinued operations	–	(0.60)	(8.95)
Other nonregulated earnings (loss) – discontinued operations *(b)*	**(0.38)**	0.77	1.72
Total earnings (loss) per share – discontinued operations	**(0.40)**	0.23	(7.20)
Total GAAP earnings (loss) per share – diluted	**$0.87**	$1.50	$(5.77)

(a) Not a reportable segment. Included in All Other segment results in Note 19 to the Consolidated Financial Statements.

(b) Includes tax benefit related to NRG. See Note 3 to the Consolidated Financial Statements.

While earnings from continuing operations for 2004 were flat compared with 2003, the current period results were favorably impacted by electric sales growth, short-term wholesale markets and lower depreciation, offset by the negative impact of unfavorable weather, legal settlement costs and the impacts of certain regulatory accruals, compared with the same period in 2003.

The loss from discontinued operations in 2004 is largely due to an after-tax impairment charge of $143 million related to the planned sale of Seren. The after-tax impairment charge was increased in the fourth quarter of 2004 from the impairment estimate recorded in the third quarter of 2004 based on further developed market information, as well as preliminary feedback from prospective buyers. The earnings in 2003 from discontinued operations are primarily due to an adjustment to previously estimated tax benefits related to Xcel Energy's write-off of its investment in NRG. NRG recorded more than $3 billion of asset impairment and other charges in 2002 as it commenced its financial restructuring. Results from discontinued operations are discussed in the Discontinued Operations section later.

Common Stock Dilution Dilution, primarily from common stock and convertible securities issued in 2002, reduced the utility segment earnings from continuing operations by 12 cents per share for 2003, compared with average common stock and equivalent levels in 2002. Total earnings from continuing operations were reduced by 11 cents per share for 2003, compared with 2002 share levels. In 2004, 2003 and 2002, approximately 423.3 million, 418.9 million and 384.6 million average common shares and equivalents, respectively, were used in the calculation of diluted earnings 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 Operations.

Electric Utility, Short-Term Wholesale and Commodity Trading Margins

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

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

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Margins from commodity trading activity are partially redistributed to other operating utilities of Xcel Energy, pursuant to a joint operating agreement (JOA) approved by the FERC. On a consolidated basis, the impact of the JOA is eliminated. Short-term wholesale and commodity trading margins reflect the impact of regulatory sharing, if applicable. Trading revenues, as discussed in Note 1 to the Consolidated Financial Statements, are reported net of trading costs (i.e., on a margin basis) in the Consolidated Statements of Operations. Commodity trading costs include fuel, purchased power, transmission and other related costs. The following table details the revenue and margin for base electric utility, short-term wholesale and commodity trading activities:

(Millions of dollars)	*Base Electric Utility*	*Short-Term Wholesale*	*Commodity Trading*	*Consolidated Totals*
2004				
Electric utility revenue (excluding commodity trading)	**$6,025**	**$220**	**$ –**	**$6,245**
Fuel and purchased power	**(2,916)**	**(125)**	**–**	**(3,041)**
Commodity trading revenue	**–**	**–**	**610**	**610**
Commodity trading costs	**–**	**–**	**(594)**	**(594)**
Gross margin before operating expenses	**$3,109**	**$ 95**	**$ 16**	**$3,220**
Margin as a percentage of revenue	**51.6%**	**43.2%**	**2.6%**	**47.0%**
2003				
Electric utility revenue (excluding commodity trading)	$5,756	$179	$ –	$5,935
Fuel and purchased power	(2,588)	(118)	–	(2,706)
Commodity trading revenue	–	–	333	333
Commodity trading costs	–	–	(316)	(316)
Gross margin before operating expenses	$3,168	$ 61	$ 17	$3,246
Margin as a percentage of revenue	55.0%	34.1%	5.1%	51.8%
2002				
Electric utility revenue (excluding commodity trading)	$5,218	$203	$ –	$5,421
Fuel and purchased power	(2,028)	(170)	–	(2,198)
Commodity trading revenue	–	–	1,529	1,529
Commodity trading costs	–	–	(1,527)	(1,527)
Gross margin before operating expenses	$3,190	$ 33	$ 2	$3,225
Margin as a percentage of revenue	61.1%	16.3%	0.1%	46.4%

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

Base Electric Utility Revenue

(Millions of dollars)	***2004 vs. 2003***	*2003 vs. 2002*
Sales growth (excluding weather impact)	**$ 73**	$ 59
Estimated impact of weather	**(74)**	(29)
Fuel and purchased power cost recovery	**230**	434
Air quality improvement recovery (AQIR)	**(2)**	36
Firm wholesale	**62**	30
Capacity sales	**(2)**	12
Quality of service obligations	**(12)**	(11)
Renewable development fund recovery	**(5)**	12
Other	**(1)**	(5)
Total base electric utility revenue increase	**$269**	$538

2004 Comparison with 2003 Base electric utility revenues increased due to weather-normalized retail sales growth of approximately 1.8 percent, higher fuel and purchased power costs, which are largely passed through to customers, and higher revenues from firm wholesale customers. Partially offsetting the higher revenues was the impact of significantly cooler summer temperatures in 2004 compared with the summer of 2003, as well as estimated customer refunds related to quality-of-service obligations in Colorado.

2003 Comparison with 2002 Base electric utility revenues increased due to weather-normalized retail sales growth of approximately 1.5 percent, higher fuel and purchased power costs, which are largely passed through to customers, and higher capacity sales in Texas. In addition, the AQIR was implemented in Colorado in January 2003 for the recovery of investments and related costs to improve air quality. Partially offsetting the higher revenues was the impact of warmer temperatures during the summer of 2002 compared with the summer of 2003, as well as 2003 rate reductions related to lower property taxes in Minnesota and estimated customer refunds related to service quality requirements in Colorado.

Base Electric Utility Margin

(Millions of dollars)	***2004 vs. 2003***	*2003 vs. 2002*
Estimated impact of weather	**$(56)**	$(23)
Sales growth (excluding weather impact)	**55**	48
Purchased capacity costs	**(12)**	(50)
Other cost recovery	**(18)**	(13)
Quality of service obligations	**(12)**	(11)
Renewable development fund recovery	**(5)**	12
Capacity sales	**(2)**	12
Regulatory accruals and other	**(9)**	3
Total base electric utility margin decrease	**$(59)**	$(22)

2004 Comparison to 2003 Base electric utility margin decreased due to the impact of weather, higher purchased capacity costs associated with new contracts to support growth, higher fuel and purchased energy costs not recovered through direct pass-through recovery mechanisms, mainly in Wisconsin, and regulatory accruals associated with potential customer refunds related to service quality obligations in Colorado and fuel reconciliation proceedings in Texas. These decreases were partially offset by weather-normalized sales growth.

2003 Comparison to 2002 Base electric utility margin decreased due mainly to higher purchased capacity costs associated with new contracts to support growth, the allowed recovery of fuel and purchased power costs in excess of actual costs in 2002 under the sharing provisions of the incentive cost adjustment mechanism in Colorado, compared with passing through costs with no sharing provisions under the interim adjustment clause in 2003, and the impact of weather. Also decreasing margin were 2003 rate reductions related to lower property taxes in Minnesota and estimated refunds to customers related to service quality requirements in Colorado. The decreases were partially offset by weather-normalized sales growth, the implementation of the AQIR and higher capacity sales, as previously discussed.

Short-Term Wholesale and Commodity Trading Margin

2004 Comparison to 2003 Short-term wholesale and commodity trading margins increased approximately $33 million in 2004 compared with 2003. The increase reflects a number of market factors, including higher market prices, additional resources available for sale and a pre-existing contract, which provided approximately $17 million of short-term wholesale margins in 2004 and expired in the first quarter of 2004.

2003 Comparison to 2002 Short-term wholesale and commodity trading margins increased approximately $43 million in 2003 compared with 2002. The increase reflects more favorable market conditions in the northern regions.

Natural Gas Utility Margins

The following table details the changes in natural gas utility revenue 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.

(Millions of dollars)	***2004***	*2003*	*2002*
Natural gas utility revenue	**$1,924**	$1,685	$1,341
Cost of natural gas purchased and transported	**(1,446)**	(1,191)	(838)
Natural gas utility margin	**$ 478**	$ 494	$ 503

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

Natural Gas Revenue

(Millions of dollars)	***2004 vs. 2003***	*2003 vs. 2002*
Sales growth (excluding weather impact)	**$ (3)**	$ 15
Purchased natural gas adjustment clause recovery	**257**	346
Rate changes – Colorado	**(15)**	(14)
Estimated impact of weather	**(10)**	–
Transportation and other	**10**	(3)
Total natural gas revenue increase	**$239**	$344

2004 Comparison to 2003 Natural gas revenue increased primarily due to higher natural gas costs in 2004, which are passed through to customers. Retail natural gas weather-normalized sales declined in 2004, largely due to the rising cost of natural gas and its impact on customer usage.

2003 Comparison to 2002 Natural gas revenue increased mainly due to higher natural gas costs in 2003, which are passed through to customers.

Natural Gas Margin

(Millions of dollars)	***2004 vs. 2003***	*2003 vs. 2002*
Sales growth (excluding weather impact)	**$ –**	$ 5
Estimated impact of weather on firm sales volume	(5)	(4)
Rate changes – Colorado	**(15)**	(14)
Transportation and other	4	4
Total natural gas margin decrease	**$(16)**	$(9)

2004 Comparison to 2003 Natural gas margin decreased due to a full year of the base rate decrease, which was effective July 1, 2003, agreed to in the settlement of the PSCo 2002 general rate case and the impact of warmer winter temperatures in 2004 compared with 2003. The rate case settlement agreement is discussed further under Factors Affecting Results of Continuing Operations.

2003 Comparison to 2002 Natural gas margin decreased due to the rate decrease discussed above and the impact of warmer winter temperatures in 2003 compared with 2002. The rate case settlement agreement is discussed further under Factors Affecting Results of Continuing Operations.

Weather Xcel Energy's earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase expenses. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses, which affects overall results. The impact of weather on earnings is based on the number of customers, temperature variances and the amount of gas or electricity the average customer historically has used 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 2004 decreased earnings by an estimated 8 cents per share;
– weather in 2003 had minimal impact on earnings per share; and
– weather in 2002 increased earnings by an estimated 6 cents per share.

Nonregulated Operating Margins

The following table details the changes in nonregulated revenue and margin included in continuing operations:

(Millions of dollars)	***2004***	*2003*	*2002*
Nonregulated and other revenue	**$161**	$222	$211
Nonregulated cost of goods sold	**(83)**	(143)	(110)
Nonregulated margin	**$ 78**	$ 79	$101

2004 Comparison to 2003 Nonregulated revenue decreased in 2004, due primarily to the discontinued consolidation of an investment in an independent power producing entity that was no longer majority owned.

2003 Comparison to 2002 Nonregulated revenue increased in 2003, due mainly to increased revenues at Utility Engineering. Nonregulated margin decreased in 2003, due to higher cost of goods sold at a subsidiary of Utility Engineering.

Non-Fuel Operating Expense and Other Items

Other Utility Operating and Maintenance Expenses Other utility operating and maintenance expenses for 2004 increased by approximately $22 million, or 1.4 percent, compared with 2003. Of the increase, $12 million of increased costs are offset by increased revenue, including those incurred to assist with the storm damage repair in Florida. The remaining increase of $10 million is primarily due to lower pension credits and higher employee benefit costs of $31 million, higher electric service reliability costs of $9 million, higher information technology costs of $8 million, higher legal settlement costs of $7 million, higher plant-related costs of $4 million, higher costs related to a customer billing system conversion of $4 million and $4 million of increased costs primarily related to compliance with the Sarbanes-Oxley Act of 2002. The higher costs were partially offset by lower compensation costs of $43 million, lower costs associated with inventory adjustments of $14 million and lower private fuel storage costs of $6 million.

Other utility operating and maintenance expenses increased $90 million, or 6.0 percent, in 2003 compared with 2002. The increase is due primarily to higher employee-related costs, including higher performance-based compensation of $36 million, restricted stock unit grants of $29 million, lower pension credits of $19 million and higher medical and health care costs of $9 million. In 2002, there were no restricted stock unit grants and only a partial award of performance-based compensation. In addition, other utility operating and maintenance expenses for 2003 reflects inventory write-downs of $8 million, higher uncollectible accounts receivable of $3 million, higher reliability expenses of $6 million and a software project write-off of $2 million. The increase was partially offset by lower information technology costs resulting from centralization.

Other Nonregulated Operating and Maintenance Expenses Other nonregulated operating and maintenance expenses decreased $14 million, or 19.6 percent, in 2004 compared with 2003. This decrease resulted from the dissolution of Planergy and the discontinued consolidation of an investment in an independent power producing entity that was no longer majority owned after the divestiture of NRG. See additional discussion of the total results for each nonregulated subsidiary later.

Other nonregulated operating and maintenance expenses decreased $21 million, or 23.2 percent, in 2003 compared with 2002. The 2002 expenses included employee severance costs at the holding company. These expenses are included in the results for each nonregulated subsidiary, as discussed later.

Depreciation and Amortization Depreciation and amortization expense for 2004 decreased by approximately $21 million, or 2.8 percent, compared with 2003, and $18 million, or 2.4 percent, in 2003 compared with 2002. The fluctuations are largely due to several regulatory decisions in 2003. In 2004, as a result of a Minnesota Public Utilities Commission (MPUC) order, NSP-Minnesota modified its decommissioning expense recognition, which served to reduce decommissioning accruals by approximately $18 million compared with 2003.

In addition, effective July 1, 2003, the Colorado Public Utilities Commission (CPUC) lengthened the depreciable lives of certain electric utility plant at PSCo as a part of the general Colorado rate case, reducing annual depreciation expense by $20 million. PSCo experienced the full impact of the annual reduction in 2004, resulting in a decrease in depreciation expense of $10 million for 2004 compared with 2003.

During 2003, the Minnesota Legislature authorized additional spent nuclear fuel storage at the Prairie Island nuclear plant. In December 2003, the MPUC extended the authorized depreciable lives of the two generating units at the Prairie Island nuclear plant, retroactive to Jan. 1, 2003, reducing depreciation by $22 million.

Special Charges Special charges in 2004 were $17.6 million related to the settlement of shareholder litigation. Special charges reported in 2003 relate to the TRANSLink Transmission Co., LLC (TRANSLink) project and NRG restructuring costs. Special charges for 2002 include NRG restructuring costs, as discussed later, but were largely related to regulated utility costs. Regulated utility earnings from continuing operations were reduced by approximately 2 cents per share in 2002 due to a $5 million regulatory recovery adjustment for SPS and $9 million in employee separation costs associated with a restaffing initiative for utility and service company operations. See Note 2 to the Consolidated Financial Statements for further discussion of these items.

Interest and Other Income, Net of Nonoperating Expenses Interest and other income, net of nonoperating expenses increased $5 million in 2004 compared with 2003. The increase is due to interest income related to the finalization of prior-period Internal Revenue Service (IRS) audits of $10.5 million. Partially offsetting the increase was the impact of a Utility Engineering gain on the sale of water rights in 2003, net of write-offs of certain intangible assets.

Interest and other income, net of nonoperating expenses decreased $27 million in 2003 compared with 2002. Interest income decreased $13 million primarily due to interest received on tax refunds in 2002. Other income decreased $10 million primarily due to a gain on the sale of contracts at Planergy in 2002.

Interest and Financing Costs Interest charges and financing costs decreased approximately $16 million, or 3.6 percent, for 2004, compared with 2003. The decrease for the year reflects savings from refinancing higher coupon debt during 2003 and lower credit line fees, partially offset by interest expense related to prior-period IRS audits.

Interest and financing costs increased approximately $30 million, or 7.1 percent, for 2003 compared with 2002. This increase was due to the full-year impact of the issuance of long-term debt in the latter part of 2002 intended to reduce dependence on short-term debt. In addition, during 2002, Xcel Energy incurred approximately $15 million to redeem temporary holding company debt. During 2003, Xcel Energy issued approximately $1.7 billion of long-term debt to refinance higher coupon debt. During 2002, certain long-term debt was refinanced at higher interest rates.

Income Tax Expense The effective tax rate was 23.2 percent for the year 2004, compared with 24.6 percent for the same period in 2003. Significant tax benefits were recorded during the fourth quarters of 2004 and 2003 due to the resolution of tax audit issues, largely related to prior periods.

Significant income tax audit activity occurring in 2003 continued in 2004. With the exception of the corporate-owned life insurance (COLI) loan interest deductibility, as discussed in Note 16, during 2004, Xcel Energy concluded IRS income tax audit and appeal activities spanning several examination cycles dating back to 1993. In addition, the IRS nearly completed the examination cycle ended 2001 and began its review of Xcel Energy's 2002 and 2003 tax years.

In 2004, income tax benefits of $39.3 million were recorded, including $28.9 million related to the successful resolution of various IRS audit issues and other adjustments to current and deferred taxes related to prior years, $7.7 million for the 2003 return-to-actual true-up and $2.7 million from revisions to benefits related to asset and foreign power sales. Excluding the tax benefits, the effective rate for 2004 would have been 28.9 percent.

In 2003, income tax benefits of $36 million were recorded to reflect the resolution of tax audit issues related to prior years. The tax issues resolved during 2003 included the tax deductibility of certain merger costs associated with the mergers to form Xcel Energy and New Century Energies, Inc. (NCE) and the deductibility, for state purposes, of certain tax benefit transfer lease benefits. Excluding these tax benefits, the effective rate for 2003 would have been 29.7 percent. See Note 10 to the Consolidated Financial Statements.

Other Nonregulated Subsidiaries and Holding Company 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 (Millions of dollars)	***2004***	*2003*	*2002*
Eloigne Company	**$ 8.5**	$ 7.7	$ 8.0
Planergy	**(1.3)**	(7.7)	(1.7)
Financing costs – holding company	**(44.7)**	(44.1)	(47.3)
Special charges – holding company	**(10.3)**	(11.2)	(2.9)
Other nonregulated and holding company results	**16.3**	19.3	2.1
Total nonregulated/holding company loss – continuing operations	**$(31.5)**	$(36.0)	$(41.8)

Contribution to Xcel Energy's earnings per share	***2004***	*2003*	*2002*
Eloigne Company	**$ 0.02**	$ 0.02	$ 0.02
Planergy	**–**	(0.02)	–
Financing costs and preferred dividends – holding company	**(0.08)**	(0.09)	(0.13)
Special charges – holding company	**(0.03)**	(0.03)	(0.01)
Other nonregulated and holding company results	**0.04**	0.05	0.01
Total nonregulated/holding company loss per share – continuing operations	**$(0.05)**	$(0.07)	$(0.11)

Eloigne Company Eloigne invests in affordable housing that qualifies for federal and state tax credits. Eloigne's earnings contribution is expected to decline slightly each year as tax credits on mature affordable housing projects begin to decline.

Planergy Planergy provided energy management services. Planergy's losses were lower in 2004 due to the dissolution of its business. Its losses were lower in 2002 largely due to pretax gains of approximately $8 million from the sale of a portfolio of energy management contracts, which reduced losses by approximately 2 cents per share.

Financing Costs and Preferred Dividends Nonregulated 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.

In November 2002, the Xcel Energy holding company issued temporary financing, which included detachable options for the purchase of Xcel Energy notes, which were convertible to Xcel Energy common stock. This temporary financing was replaced with long-term holding company financing in late November 2002. Costs incurred to redeem the temporary financing included a redemption premium of $7.4 million, $5.2 million of debt discount associated with the detachable option, and other issuance costs, which increased financing costs and reduced 2002 earnings by 2 cents per share.

The earnings-per-share impact of financing costs and preferred dividends for 2004 and 2003 included above reflects dilutive securities, as discussed further in Note 11 to the Consolidated Financial Statements. The impact of the dilutive securities, if converted, is a reduction of interest expense resulting in an increase in net income of approximately $15 million, or 4 cents per share, in 2004, and $11 million, or 3 cents per share, in 2003.

Holding Company Special Charges During 2004, special charges at the holding company consisted of an accrual of $17.6 million for a settlement agreement related to shareholder lawsuits. See Note 2 to the Consolidated Financial Statements for further discussion of these special charges.

During 2002, NRG experienced credit-rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events ultimately led to the restructuring of NRG in late 2002 and its bankruptcy filing in May 2003. See Note 4 to the Consolidated Financial Statements. Certain costs related to NRG's restructuring were incurred at the holding company level and included in continuing operations and reported as Special Charges. Approximately $12 million of these costs were incurred in 2003 and $5 million were incurred in 2002, which reduced after-tax earnings by approximately 2 cents per share and 1 cent per share, respectively. Costs in 2003 included approximately $32 million of financial advisor fees, legal costs and consulting costs related to the NRG bankruptcy transaction. These charges were partially offset by a $20 million pension curtailment gain related to the termination of NRG employees from Xcel Energy's pension plan. In 2003, Xcel Energy also recorded a $7 million charge in connection with the suspension of the formation of the independent transmission company TRANSLink. See Note 2 to the Consolidated Financial Statements for further discussion of these special charges.

Other Nonregulated In 2003, Utility Engineering sold water rights, resulting in a pretax gain (reported as nonoperating income) of $15 million. The gain increased after-tax income by approximately 2 cents per share.

Statement of Operations Analysis – Discontinued Operations

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

(Millions of dollars)	***2004***	*2003*	*2002*
Income (loss)			
Viking Gas Transmission Co.	**$ 1.3**	$ 21.9	$ 9.4
Black Mountain Gas	**–**	2.4	1.0
Cheyenne Light, Fuel and Power Co.	**(10.3)**	2.5	3.4
Regulated utility segments – income (loss)	**(9.0)**	26.8	13.8
NRG segment – loss	**–**	(251.4)	(3,444.1)
Xcel Energy International	**7.3**	(45.5)	(17.1)
e prime	**(1.8)**	(17.8)	1.5
Seren Innovations	**(156.5)**	(18.3)	(27.1)
Other	**1.9**	(1.6)	(2.4)
NRG-related tax benefits (expense)	**(12.8)**	404.4	706.0
Nonregulated/other – income (loss)	**(161.9)**	321.2	660.9
Total income (loss) from discontinued operations	**$(170.9)**	$ 96.6	$(2,769.4)
Income (loss) per share			
Viking Gas Transmission Co.	**$ –**	$ 0.05	$ 0.03
Black Mountain Gas	**–**	0.01	–
Cheyenne Light, Fuel and Power Co.	**(0.02)**	–	–
Regulated utility segments – income per share (loss)	**(0.02)**	0.06	0.03
NRG segment – loss per share	**–**	(0.60)	(8.95)
Xcel Energy International	**0.02**	(0.11)	(0.05)
e prime	**–**	(0.04)	–
Seren Innovations	**(0.37)**	(0.04)	(0.07)
Other	**–**	–	0.01
NRG-related tax benefits (expense)	**(0.03)**	0.96	1.83
Nonregulated/other – income (loss) per share	**(0.38)**	0.77	1.72
Total income (loss) per share from discontinued operations	**$ (0.40)**	$ 0.23	$ (7.20)

Regulated Utility Results – Discontinued Operations

During 2003, Xcel Energy completed the sale of two subsidiaries in its regulated natural gas utility segment: Viking, including its interest in Guardian Pipeline, LLC, and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded for the natural gas utility segment, primarily related to the sale of Viking.

Viking had minimal income in 2003, as it was sold in January of that year. Income from Viking was higher in 2002, compared with 2001, primarily due to increased revenues.

During January 2004, Xcel Energy reached an agreement to sell its regulated electric and natural gas subsidiary Cheyenne. As a result of this agreement, Xcel Energy is reporting Cheyenne results as a component of discontinued operations for all periods presented. The sale was completed in January 2005 and resulted in an after-tax loss of approximately $13 million, or 3 cents per share, which was accrued at Dec. 31, 2004.

NRG Results – Discontinued Operations

Due to NRG's emergence from bankruptcy in December 2003 and Xcel Energy's corresponding divestiture of its ownership interest in NRG, Xcel Energy's share of NRG results for current and prior periods is now shown as a component of discontinued operations.

2004 NRG Results Compared with 2003 As a result of NRG's emergence from bankruptcy in December 2003, Xcel Energy did not retain an ownership interest in NRG after that date. Therefore, Xcel Energy financial statements do not contain any results of NRG operations in 2004. See Note 4 to the Consolidated Financial Statements and the following discussion for further information.

2003 NRG Results Compared with 2002 As a result of NRG's bankruptcy filing in May 2003, Xcel Energy ceased the consolidation of NRG and began accounting for its investment in NRG using the equity method in accordance with Accounting Principles Board Opinion No. 18 – "The Equity Method of Accounting for Investments in Common Stock." After changing to the equity method, Xcel Energy was limited in the amount of NRG's losses subsequent to the bankruptcy date that it was required to record. In accordance with these limitations under the equity method, Xcel Energy stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provided for loss recognition by Xcel Energy until its investment in NRG was written off to zero, with further loss recognition to continue if its financial commitments to NRG existed beyond amounts already invested. Xcel Energy initially recorded more losses than the limitations allow as of June 30, 2003, but upon Xcel Energy's divestiture of its interest in NRG, the NRG losses recorded in excess of Xcel Energy's investment in and financial commitment to NRG were reversed in the fourth quarter of 2003. This resulted in a noncash gain of $111 million, or 26 cents per share, for the quarter and an adjustment of the total NRG losses recorded for the year 2003 to $251 million, or 60 cents per share.

NRG's results included in Xcel Energy's earnings for 2003 were as follows:

(Millions of dollars)	*Six months ended June 30, 2003*
Total NRG loss	$(621)
Losses not recorded by Xcel Energy under the equity method*	370
Equity in losses of NRG included in Xcel Energy results for 2003	$(251)

** These represent NRG losses incurred in the first and second quarters of 2003 that were in excess of the amounts recordable by Xcel Energy under the equity method of accounting limitations discussed previously.*

Following its credit downgrade in July 2002, NRG experienced credit and liquidity constraints and commenced a financial and business restructuring, including a voluntary petition for bankruptcy protection. This restructuring created significant incremental costs and resulted in numerous asset impairments as the strategic and economic value of assets under development and in operation changed.

NRG's asset impairments and related charges in 2003 were approximately $540 million related to its NEO landfill gas projects and equity investments, planned disposals of domestic and international projects, and regulatory developments and changing circumstances that adversely affected NRG's ability to recover the carrying value of certain investments. As of the bankruptcy filing date (May 14, 2003), Xcel Energy had recognized $263 million of NRG's impairments and related charges as these charges were recorded by NRG prior to May 14, 2003. Consequently, Xcel Energy recorded its equity in NRG results in excess of its financial commitment to NRG under the settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG's creditors. These excess losses were reversed upon NRG's emergence from bankruptcy in December 2003, as discussed previously.

In 2003, NRG's operating results (excluding the unusual items discussed above) were affected by higher market prices due to higher natural gas prices and an increase in capacity revenues due to additional projects becoming operational in the later part of 2002. In addition, the sale of an NRG investment in 2002 resulted in a favorable impact in 2003 as the investment generated substantial equity losses in the prior years. The increase was offset by losses incurred on contracts in Connecticut due to increased market prices, increased operating expenses, contract terminations and liquidated damages triggered by NRG's financial condition and additional restructuring charges.

During 2002, the tax filing status of NRG for 2002 and future years changed from being included as part of Xcel Energy's consolidated federal income tax group to filing on a stand-alone basis.

Other Nonregulated Results – Discontinued Operations

On Sept. 27, 2004, Xcel Energy's board of directors approved management's plan to pursue the sale of Seren, a wholly owned broadband communications services subsidiary. Seren delivers cable television, high-speed Internet and telephone service over an advanced network to approximately 45,000 customers in St. Cloud, Minn., and Concord and Walnut Creek, Calif. As a result of the decision, Seren is accounted for as discontinued operations. The sale of such investment is expected to be completed by mid-2005.

During 2003, Xcel Energy's board of directors approved management's plan to exit businesses conducted by e prime and Xcel Energy International. e prime ceased conducting business in 2004. Also during 2004, Xcel Energy completed the sales of the Argentina subsidiaries of Xcel Energy International.

2004 Nonregulated Results Compared with 2003 Results of discontinued nonregulated operations in 2004 include the impact of the sales of the Argentina subsidiaries of Xcel Energy International. The sales were completed in three transactions with a total sales price of approximately $31 million, including certain adjustments that reached finalization in the fourth quarter of 2004. Approximately $15 million was placed in escrow, which is expected to remain in place until at least the end of the first quarter of 2005, to support customary indemnity obligations under the sales agreement. In addition to the sales price, Xcel Energy also received approximately $21 million at the closing of one transaction as redemption of its capital investment. The sales resulted in a gain of approximately $8 million, including the realization of approximately $7 million of income tax benefits realizable upon sale of the Xcel Energy International assets.

In addition, 2004 results from discontinued operations include the impact of an after-tax impairment charge for Seren, including disposition costs, of $143 million, or 34 cents per share. The impairment charge was recorded based on operating results, market conditions and preliminary feedback from prospective buyers.

2003 Nonregulated Results Compared with 2002 Results of discontinued nonregulated operations, other than NRG, include an after-tax loss of $59 million, or 14 cents per share, for the disposal of Xcel Energy International's assets, based on the estimated fair value of such assets. These losses from discontinued nonregulated operations also include a charge of $16 million for costs of settling a Commodity Futures Trading Commission trading investigation of e prime.

Tax Benefits Related to Investment in NRG Xcel Energy has recognized tax benefits related to the divestiture of NRG. These tax benefits, since related to Xcel Energy's investment in discontinued NRG operations, also are reported as discontinued operations.

During 2002, Xcel Energy recognized an initial estimate of the expected tax benefits of $706 million. Based on the results of a 2003 preliminary tax basis study of NRG, Xcel Energy recorded $404 million of additional tax benefits in 2003. In 2004, the NRG basis study was updated and previously recognized tax benefits were reduced by $16 million.

Based on current forecasts of taxable income and tax liabilities, Xcel Energy expects to realize approximately $1.1 billion of cash savings from these tax benefits through a refund of taxes paid in prior years and reduced taxes payable in future years. Xcel Energy used $405 million and $116 million of these tax benefits in 2004 and 2003, respectively, and expects to use $145 million in 2005. The remainder of the tax benefit carry forward is expected to be used over subsequent years.

Factors Affecting Results of Continuing Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect our ability to recover our costs from customers. In addition, Xcel Energy's nonregulated businesses have had an adverse impact on Xcel Energy's earnings in 2004, 2003 and 2002. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including the following:

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. The United States economy continues to show evidence of recovery as measured by growth in the gross domestic product. However, certain operating costs, such as those for insurance and security, have increased during the past three years due to economic uncertainty, terrorist activity and war or the threat of war. Management cannot predict the impact of a future economic slowdown, fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material adverse impact to its results of operations, future growth or ability to raise capital resulting from a slowdown in future economic growth.

Sales Growth

In addition to the impact of weather, customer sales levels in Xcel Energy's regulated utility businesses can vary with economic conditions, energy prices, customer usage patterns and other factors. Weather-normalized sales growth for retail electric utility customers was estimated to be 1.8 percent in 2004 compared with 2003, and 1.5 percent in 2003 compared with 2002. Weather-normalized sales growth for firm natural gas utility customers was estimated to be approximately (1.9) percent in 2004 compared with 2003 and 1.6 percent in 2003 compared with 2002. Projections indicate that weather-normalized sales growth in 2005 compared with 2004 will be approximately 2.2 percent for retail electric utility customers and 1.1 percent for firm gas utility customers.

Pension Plan Costs and Assumptions

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 12 to the Consolidated Financial Statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs have been increasing in recent years, and are expected to increase further over the next several years, due to lower-than-expected investment returns experienced in prior years and decreases in interest rates used to discount benefit obligations. While investment returns exceeded the assumed level of 9.25 percent in 2003 and 9.0 percent in 2004, investment returns in 2001 and 2002 were below the assumed level of 9.5 percent and discount rates have declined from the 7.25-percent to 8-percent levels used in 1999 through 2002 cost determinations to 6.25 percent used in 2004. Xcel Energy continually reviews its pension assumptions and, in 2005, expects to change the investment return assumption to 8.75 percent and the discount rate assumption to 6.0 percent.

The investment gains or losses resulting from the difference between the expected pension returns assumed on smoothed or "market-related" asset levels and actual returns earned is deferred in the year the difference arises and recognized over the subsequent five-year period. This gain or loss recognition occurs by using a five-year, moving-average value of pension assets to measure expected asset returns in the cost-determination process, and by amortizing deferred investment gains or losses over the subsequent five-year period. Based on the use of average market-related asset values, and considering the expected recognition of past investment gains and losses over the next five years, achieving the assumed rate of asset return of 8.75 percent in each future year and holding other assumptions constant, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes in continuing operations will increase from a credit, or negative expense, of $27 million in 2004 to an expense of $8 million in 2005 and $20 million in 2006. Pension costs are currently a credit due to the recognized investment asset returns exceeding the other pension cost components, such as benefits earned for current service and interest costs for the effects of the passage of time on discounted obligations.

Xcel Energy bases its discount rate assumption on benchmark interest rates quoted by an established credit rating agency, Moody's Investors Service (Moody's), and has consistently benchmarked the interest rate used to derive the discount rate to the movements in the long-term corporate bond indices for bonds rated Aaa through Baa by Moody's, which have a period to maturity comparable to our projected benefit obligations. At Dec. 31, 2003, the annualized Moody's Baa index rate was 6.61 percent and the Aaa index rate was 5.63 percent. The corresponding pension discount rate was 6.25 percent. At Dec. 31, 2004, the annualized Moody's Baa index rate had declined 51 basis points to 6.10 percent, and the Aaa index rate had declined 20 basis points to 5.43 percent. Accordingly, the discount rate as of Dec. 31, 2004, was lowered 25 basis points to 6.00 percent. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2005 pension cost determinations.

If Xcel Energy were to use alternative assumptions for pension cost determinations, a 1-percent change would result in the following impacts on the estimated pension costs recognized by Xcel Energy for financial reporting purposes:
– a 100 basis point higher rate of return, 9.75 percent, would decrease 2005 pension costs by $17.9 million;
– a 100 basis point lower rate of return, 7.75 percent, would increase 2005 pension costs by $17.9 million;
– a 100 basis point higher discount rate, 7.0 percent, would decrease 2005 pension costs by $8.3 million; and
– a 100 basis point lower discount rate, 5.0 percent, would increase 2005 pension costs by $6.2 million.

Alternative Employee Retirement Income Security Act of 1974 (ERISA) funding assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be affected 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 in recent years for Xcel Energy's pension plans, and do not require funding in 2005. Assuming that future asset return levels equal the actuarial assumption of 8.75 percent for the years 2005 and 2006, Xcel Energy projects, under current funding regulations, that no cash funding would be required for 2005 and cash funding of $9 million would be required for 2006. Actual performance can affect these funding requirements significantly. Current funding regulations are under legislative review in 2005 and, if not retained in their current form, could change these funding requirements materially.

Regulation

Xcel Energy, its utility subsidiaries and certain of its nonutility subsidiaries are subject to extensive regulation by the SEC under the PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties and intra-system sales of certain non-power goods and services. In addition, the PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. See further discussion of financing restrictions under Liquidity and Capital Resources.

Xcel Energy's utility subsidiaries also are regulated by the FERC and state regulatory commissions. 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 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 investment, sales growth, conservation and demand-side management efforts, and the cost of capital. In addition, the return on equity authorized is set by regulatory commissions in rate proceedings. The most recently authorized electric utility returns are 11.47 percent for NSP-Minnesota, 11.9 percent for NSP-Wisconsin, 10.75 percent for PSCo and 11.5 percent for SPS.

Most of the retail rates for Xcel Energy's utility subsidiaries provide for periodic adjustments to billings and revenues to allow for recovery of changes in the cost of fuel for electric generation, purchased energy, purchased natural gas for resale and, in Minnesota and Colorado, conservation, energy-management program costs and certain other costs. In Colorado, certain purchased electric capacity costs are recovered through a rate-adjustment mechanism. In Minnesota, generally changes in purchased electric capacity costs are not recovered through these rate-adjustment mechanisms. For Wisconsin electric operations, where automatic cost-of-energy adjustment clauses are not allowed, the biennial retail rate review process and an interim fuel-cost hearing process provide the opportunity for rate recovery of changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In Colorado, PSCo had an interim adjustment clause that allowed for recovery of all prudently incurred electric fuel and purchased energy expenses in 2003. In 2004, PSCo generally recovered all prudently incurred electric fuel and purchased energy costs through an electric commodity adjustment clause. Additionally, this fuel mechanism also has in place a sharing among customers and shareholders of certain fuel and energy costs, with an $11.25 million maximum on any cost sharing over or under an allowed electric commodity adjustment formula rate, and a sharing among shareholders and customers of certain gains and losses on trading margins. In 2004, PSCo estimated that energy costs incurred were lower than the commodity adjustment formula rate and accrued an incentive of $11.25 million at Dec. 31, 2004.

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 distribution system. In addition to filing for increases in base rates charged to customers to recover the costs associated with such investments, in 2002 and 2003 approval was obtained from Colorado and Minnesota regulators to recover, through a rate surcharge, certain costs to upgrade plants and lower emissions in the Denver and Minneapolis-St. Paul metropolitan areas. These rate recovery mechanisms are expected to provide significant cash flows to enable recovery of costs incurred on a timely basis.

Regulated public utilities are allowed to record as regulatory assets certain costs that are expected to be recovered from customers in future periods and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, nonregulated enterprises would expense these costs and recognize the income in the current period. If restructuring or other changes in the regulatory environment occur, Xcel Energy may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from its balance sheet. Such changes could have a material effect on Xcel Energy's results of operations in the period the write-off is recorded.

At Dec. 31, 2004, Xcel Energy reported on its balance sheet regulatory assets of approximately $851 million and regulatory liabilities of approximately $1.6 billion that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. See Notes 1 and 18 to the Consolidated Financial Statements for further discussion of regulatory deferrals.

Tax Matters

Interest Expense Deductibility PSCo's wholly owned subsidiary, PSR Investments, Inc. (PSRI), owns and manages permanent life insurance policies, known as COLI policies, on some of PSCo's employees. At various times, borrowings have been made against the cash values of these COLI policies and deductions taken on the interest expense on these borrowings. The IRS has challenged the deductibility of such interest expense deductions and has disallowed the deductions taken in tax years 1993 through 1999. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2004, would reduce earnings by an estimated $311 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) are also included, the total exposure through Dec. 31, 2004, is approximately $368 million. Xcel Energy estimates its annual earnings for 2005 would be reduced by $40 million, after tax, which represents 9 cents per share, if COLI interest expense deductions were no longer available. See Note 16 to the Consolidated Financial Statements for further discussion.

Accounting for Uncertain Tax Positions In late July 2004, the Financial Accounting Standards Board (FASB) discussed potential changes or clarifications in the criteria for recognition of tax benefits, which may result in raising the threshold for recognizing tax benefits, which have some degree of uncertainty. The FASB has not issued any proposed guidance, but an exposure draft may be released in the first quarter of 2005. Xcel Energy is unable to determine the impact or timing of any potential accounting changes required by the FASB, but such changes could have a material financial impact.

Environmental Matters

Environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and wastes, remediation of contaminated sites and monitoring of discharges to the environment. A trend of greater environmental awareness and increasingly stringent regulation has caused, and may continue to cause, 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 wastes were approximately:
- $133 million in 2004;
- $133 million in 2003; and
- $138 million in 2002.

Xcel Energy expects to expense an average of approximately $154 million per year from 2005 through 2009 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 on environmental improvements at regulated facilities were approximately:
- $20.9 million in 2004;
- $58.5 million in 2003; and
- $107.8 million in 2002.

The regulated utilities expect to incur approximately $221 million in capital expenditures for compliance with environmental regulations and environmental improvements in 2005 and approximately $980 million of related expenditures during the period from 2006 through 2009. Approximately $171 million and $787 million of these expenditures, respectively, are related to modifications to reduce the emissions of NSP-Minnesota's generating plants located in the Minneapolis-St. Paul metropolitan area pursuant to the metropolitan emissions reduction project, which are recoverable from customers through cost-recovery mechanisms. See Notes 16 and 17 to the Consolidated Financial Statements for further discussion of Xcel Energy's environmental contingencies.

Impact of Nonregulated Investments

In the past, Xcel Energy's investments in nonregulated operations have 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 will continue to have such a significant impact on its results. Xcel Energy does not expect to make any material investments in nonregulated projects. Xcel Energy's remaining nonregulated businesses may carry a higher level of risk than its traditional utility businesses.

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

Accounting Policy	*Judgments/Uncertainties Affecting Application*	*See Additional Discussion At*
Regulatory Mechanisms and Cost Recovery	– External regulatory decisions, requirements and regulatory environment – Anticipated future regulatory decisions and their impact – Impact of deregulation and competition on ratemaking process and ability to recover costs	Management's Discussion and Analysis: Factors Affecting Results of Continuing Operations Regulation Notes to Consolidated Financial Statements Notes 1, 16 and 18
Nuclear Plant Decommissioning and Cost Recovery	– Costs of future decommissioning – Availability of facilities for waste disposal – Approved methods for waste disposal – Useful lives of nuclear power plants – Future recovery of plant investment and decommissioning costs	Notes to Consolidated Financial Statements Notes 1, 16 and 17
Income Tax Accruals	– Application of tax statutes and regulations to transactions – Anticipated future decisions of tax authorities – Ability of tax authority decisions/positions to withstand legal challenges and appeals – Ability to realize tax benefits through carry backs to prior periods or carry overs to future periods	Management's Discussion and Analysis: Factors Affecting Results of Continuing Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 10 and 16
Benefit Plan Accounting	– Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition – Discount rates used in valuing benefit obligation – Actuarial period selected to recognize deferred investment gains and losses	Management's Discussion and Analysis: Factors Affecting Results of Continuing Operations Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements Notes 1 and 12
Asset Valuation	– Regional economic conditions affecting asset operation, market prices and related cash flows – Regulatory and political environments and requirements – Levels of future market penetration and customer growth	Management's Discussion and Analysis: Results of Operations Statement of Operations Analysis– Discontinued Operations Factors Affecting Results of Continuing Operations Impact of Nonregulated Investments Notes to Consolidated Financial Statements Note 3

Xcel Energy continually makes informed judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. For example:

- Probable outcomes of regulatory proceedings are assessed in cases of requested cost recovery or other approvals from regulators.
- The ability to operate plant facilities and recover the related costs over their useful operating lives, or such other period designated by our regulators, is assumed.
- Probable outcomes of reviews and challenges raised by tax authorities, including appeals and litigation where necessary, are assessed.
- Projections are made regarding earnings on pension investments, and the salary increases provided to employees over their periods of service.
- Future cash inflows of operations are projected in order to assess whether they will be sufficient to recover future cash outflows, including the impacts of product price changes and market penetration to customer groups.

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 impacts of these factors as of Dec. 31, 2004.

Recently Implemented Accounting Changes

For a discussion of significant accounting policies, see Note 1 to the Consolidated Financial Statements.

Pending Accounting Changes

Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004) "Share Based Payment" (SFAS No. 123R) – In December 2004, FASB issued SFAS No. 123R related to equity-based compensation. This statement replaces the original SFAS No. 123 – "Accounting for Stock-Based Compensation." Under SFAS No. 123R, companies are no longer allowed to account for their share-based payment awards using the intrinsic value allowed by previous accounting requirements, which did not require any expense to be recorded on stock options granted with an equal to or greater than fair market value exercise price. Instead, equity-based compensation arrangements will be measured and recognized based on the grant-date fair value using an option-pricing model (such as Black-Scholes or Binomial) that considers at least six factors identified in SFAS No. 123R. An expense related to the difference between the grant-date fair value and the purchase price would be recognized over the vesting period of the options. Under previous guidance, companies were allowed to initially estimate forfeitures or recognize them as they actually occurred. SFAS No. 123R requires companies to estimate forfeitures on the date of grant and to adjust that estimate when information becomes available that suggests actual forfeitures will differ from previous estimates. Revisions to forfeiture estimates will be recorded as a cumulative effect of a change in accounting estimate in the period in which the revision occurs.

Previous accounting guidance allowed for compensation expense related to performance share plans to be reversed if the target was not met. However, under SFAS No. 123R, compensation expense for performance share plans that expire unexercised due to the company's failure to reach a certain target stock price cannot be reversed. Any accruals made for Xcel Energy's restricted stock unit plan could not be reversed if the target was not met. Implementation of SFAS No. 123R is required for interim or annual periods beginning after June 15, 2005. Xcel Energy is required to adopt the provisions in the third quarter of 2005. Implementation is not expected to have a material impact on net income or earnings per share.

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 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 below.

Commodity Price Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation and retail distribution operations. Commodity price risk is managed by entering into both long- and short-term physical purchase and sales contracts for electric power, natural gas, coal and fuel oil. 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 subsidiaries conduct various commodity-marketing activities, including the purchase and sale of capacity, energy and energy-related instruments. These marketing activities are primarily focused on specific regions where market knowledge and experience have been obtained and are generally less than one year in length. Xcel Energy's risk management policy allows management to conduct the marketing activities within approved guidelines and limitations as approved by the company's risk management committee, which is made up of management personnel not directly involved in the activities governed by the policy.

Certain contracts within the scope of these activities qualify for hedge accounting treatment under SFAS No. 133 – "Accounting for Derivative Instruments and Hedging Activities," as amended, while others are subject to the fair value requirements of this pronouncement.

The fair value of the commodity trading contracts for continuing operations as of Dec. 31, 2004, was as follows:

(Millions of dollars)	
Fair value of trading contracts outstanding at Jan. 1, 2004	$ 4.2
Contracts realized or settled during the year	(21.6)
Fair value of trading contract additions and changes during the year	17.4
Fair value of contracts outstanding at Dec. 31, 2004	$ –

As of Dec. 31, 2004, the sources of fair value of the commodity trading and hedging net assets were as follows:

Commodity Trading Contracts

(Thousands of dollars)	*Source of Fair Value*	*Futures/Forwards* *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*
NSP-Minnesota	*1*	$ 51	$ –	$ –	$ –	$ 51
	2	874	–	–	–	874
PSCo	*1*	(922)	–	–	–	(922)
	2	(134)	–	–	–	(134)
Total futures/forwards fair value		$ (131)	$ –	$ –	$ –	$ (131)

(Thousands of dollars)	*Source of Fair Value*	*Options* *Maturity Less than 1 Year*	*Maturity 1 to 3 Years*	*Maturity 4 to 5 Years*	*Maturity Greater than 5 Years*	*Total Options Fair Value*
PSCo	*2*	$ 139	$ –	$ –	$ –	$ 139
Total options fair value		$ 139	$ –	$ –	$ –	$ 139

Hedge Contracts

(Thousands of dollars)	*Source of Fair Value*	*Futures/Forwards* *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*
PSCo	*2*	$ 1,047	$ –	$ –	$ –	$ 1,047
Total futures/forwards fair value		$ 1,047	$ –	$ –	$ –	$ 1,047

(Thousands of dollars)	*Source of Fair Value*	*Options* *Maturity Less than 1 Year*	*Maturity 1 to 3 Years*	*Maturity 4 to 5 Years*	*Maturity Greater than 5 Years*	*Total Options Fair Value*
NSP-Minnesota	*2*	$ (7,153)	$ –	$ –	$ –	$ (7,153)
NSP-Wisconsin	*2*	(1,060)	–	–	–	(1,060)
PSCo	*2*	(18,453)	1,028	–	–	(17,425)
Total options fair value		$(26,666)	$1,028	$ –	$ –	$(25,638)

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, as amended, have been excluded.

At Dec. 31, 2004, a 10-percent increase in market prices over the next 12 months for trading contracts would impact pretax income from continuing operations by approximately $(0.1) million, whereas a 10-percent decrease would impact pretax income from continuing operations by approximately $0.1 million. Hedge contracts are accounted for as a component of Other Comprehensive Income and would not directly impact earnings.

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, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movement, lognormal price distribution assumption, delta half-gamma approach for non-linear instruments and a three-day holding period for both electricity and natural gas. Previously, Xcel Energy calculated VaR using a holding period of five days for electricity and two days for natural gas. However, the methodology was changed to ensure consistency in risk measurement across both commodities. Xcel Energy's revised holding periods remain consistent with current industry practice. VaR using the current methodology for 2004 and previous methodology for 2003 are as follows:

As of Dec. 31, 2004, the calculated VaRs using the current methodology were:

Current Methodology (Millions of dollars)	*Year ended Dec. 31, 2004*	*During 2004* *Average*	*High*	*Low*
Commodity trading *(a)*	**$0.29**	**$0.97**	**$2.09**	**$0.27**

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

As of Dec. 31, 2003, the calculated VaRs using the previous methodology were:

Previous Methodology (Millions of dollars)	*Year ended Dec. 31, 2003*	*During 2003* *Average*	*High*	*Low*
Electric commodity trading *(a)*	$0.92	$0.70	$1.51	$0.29
Natural gas commodity trading *(b)*	$ –	$0.06	$0.89	$ –
Natural gas retail marketing *(b)*	$0.08	$0.32	$1.00	$0.02
Other	$ –	$0.02	$0.15	$ –

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

(b) Conducted by e prime, which is a discontinued operation.

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.

Xcel Energy engages in hedges of cash flow and fair value exposure. The fair value of interest rate swaps designated as cash flow hedges is initially recorded in Other Comprehensive Income. Reclassification of unrealized gains or losses on cash flow hedges of variable rate debt instruments from Other Comprehensive Income into earnings occurs as interest payments are accrued on the debt instrument and generally offsets the change in the interest accrued on the underlying variable rate debt. Hedges of fair value exposure are entered into to hedge the fair value of a recognized asset, liability or firm commitment. Changes in the derivative fair values that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of related hedged assets, liabilities or firm commitments. To test the effectiveness of such swaps, a hypothetical swap is used to mirror all the critical terms of the underlying debt and regression analysis is utilized to assess the effectiveness of the actual swap at inception and on an ongoing basis, if required. The assessment is done periodically to ensure the swaps continue to be effective. The fair value of interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

At Dec. 31, 2004 and 2003, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $6.8 million and $0.8 million, respectively. See Note 14 to the Consolidated Financial Statements for a discussion of Xcel Energy and its subsidiaries' interest rate swaps.

Xcel Energy and its subsidiaries also maintain trust funds, as required by the Nuclear Regulatory Commission (NRC), to fund certain costs of nuclear decommissioning, which are subject to interest rate risk and equity price risk. As of Dec. 31, 2004 and 2003, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. Per NRC mandates, 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 In addition to the risks discussed previously, Xcel Energy and its subsidiaries are 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.

At Dec. 31, 2004, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $23.4 million, while a decrease of 10 percent would have resulted in a decrease of $14.4 million.

Foreign Currency Exchange Risk Due to the discontinuance of NRG and Xcel Energy International's operations in 2003, as discussed in Notes 3 and 4 to the Consolidated Financial Statements, Xcel Energy no longer has material foreign currency exchange risk.

Liquidity and Capital Resources

Cash Flows

(Millions of dollars)	***2004***	*2003*	*2002*
Cash provided by (used in) operating activities			
Continuing operations	**$1,126**	$1,107	$1,282
Discontinued operations	**(309)**	271	433
Total	**$ 817**	$1,378	$1,715

Cash provided by operating activities for continuing operations increased $19 million during 2004 compared with 2003 due to the timing of payments made for trade payables partially offset by increased inventory costs related to higher natural gas costs, which will be collected from customers in future periods. Cash provided by operating activities for discontinued operations decreased $580 million during 2004 compared with 2003. During 2004, Xcel Energy paid $752 million pursuant to the NRG settlement agreement, which was partially offset by tax benefits received.

Cash provided by operating activities for continuing operations decreased during 2003 compared with 2002 primarily due to decreases in recovery of deferred fuel costs. Cash provided by operating activities for discontinued operations decreased during 2003 compared with 2002 due to the de-consolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. The decrease was partially offset by tax benefits received in connection with the divestiture of NRG in 2003.

(Millions of dollars)	***2004***	*2003*	*2002*
Cash provided by (used in) investing activities			
Continuing operations	**$(1,272)**	$(1,036)	$ (990)
Discontinued operations	**37**	110	(1,721)
Total	**$(1,235)**	$ (926)	$(2,711)

Cash used in investing activities for continuing operations increased $236 million during 2004 compared with 2003 primarily due to increased utility capital expenditures. Cash provided by investing activities for discontinued operations decreased $73 million during 2004 compared with 2003 primarily due to the receipt of proceeds from the sale of Viking in 2003.

Cash used in investing activities for continuing operations was approximately the same during 2003 compared with 2002 due to comparable utility construction expenditures. Cash flows for investing activities related to discontinued operations increased during 2003 compared with 2002 due to the de-consolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. NRG had significant construction expenditures during 2002 prior to its financial difficulties.

(Millions of dollars)	***2004***	*2003*	*2002*
Cash provided by (used in) financing activities			
Continuing operations	**$(111)**	$(363)	$ 115
Discontinued operations	**–**	(4)	1,465
Total	**$(111)**	$(367)	$1,580

Cash flow from financing activities related to continuing operations increased $252 million during 2004 compared with 2003 primarily due to increased short-term borrowings partially offset by a common stock repurchase.

Cash flows for financing activities related to continuing operations decreased during 2003 compared with 2002 due to refinancing activities in 2003 to better align Xcel Energy's capital structure and manage the cost of capital given the improving credit quality of Xcel Energy and its subsidiaries. During 2003, Xcel Energy and its subsidiaries extinguished $1.3 billion of long-term debt and issued approximately $1.7 billion of long-term debt, as shown in the Consolidated Statement of Capitalization. Cash flows for financing activities related to discontinued operations decreased during 2003 compared with 2002 due to the de-consolidation of NRG for 2003 reporting and the exclusion of any of its cash flows in that year. NRG obtained financing in 2002 for its construction expenditures prior to experiencing its financial difficulties.

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, Nonregulated Investments 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 2005, 2006 and 2007 are shown in the table below.

(Millions of dollars)	*2005*	*2006*	*2007*
Electric utility	$ 1,039	$1,293	$1,283
Natural gas utility	114	107	120
Common utility	87	96	94
Total utility	1,240	1,496	1,497
Other nonregulated	1	4	8
Total capital expenditures	1,241	1,500	1,505
Debt maturities	224	839	341
Total capital requirements	$1,465	$2,339	$1,846

The capital expenditure forecast includes the 750-megawatt Comanche 3 coal-fired plant in Colorado and the MERP project, which will reduce the emissions of three NSP-Minnesota's generating plants. The MERP project is expected to cost approximately $1 billion, with major construction starting in 2005 and finishing in 2009. Xcel Energy expects to recover the costs of the emission-reduction project through customer rate increases beginning in 2006. Comanche 3 is expected to cost approximately $1.35 billion, with major construction starting in 2006 and finishing in 2010. The Colorado commission has approved sharing one-third ownership of this plant with other parties. Consequently, Xcel Energy's capital expenditure forecast includes $1 billion, approximately two-thirds of the total cost.

Xcel Energy is evaluating a potential investment in a wind generation project of approximately $165 million, currently not included in the capital expenditure forecast. A decision to move forward with this type of investment will be dependent on the extension of federal tax credits related to wind generation, favorable regulatory recovery and other business considerations.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy's long-term energy needs. In addition, Xcel Energy's ongoing evaluation of restructuring requirements, compliance with future requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements. For more information, see Note 16 to the Consolidated Financial Statements.

Contractual Obligations and Other Commitments Xcel Energy has contractual obligations and other commercial 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, 2004. See additional discussion in the Consolidated Statements of Capitalization and Notes 5, 6, 15 and 16 to the Consolidated Financial Statements.

		Payments Due by Period			
(Thousands of dollars)	*Total*	*Less than 1 Year*	*1 to 3 Years*	*4 to 5 Years*	*After 5 Years*
Long-term debt principal and interest payments	$10,369,734	$ 631,129	$1,904,191	$1,849,040	$5,985,374
Capital lease obligations	105,356	6,672	12,734	12,123	73,827
Operating leases *(a)*	358,695	55,103	117,678	114,237	71,677
Unconditional purchase obligations *(b)*	11,608,993	2,282,749	2,564,718	1,936,891	4,824,635
Other long-term obligations	147,237	40,419	41,669	33,240	31,909
Payments to vendors in process	106,144	106,144	–	–	–
Short-term debt	312,300	312,300	–	–	–
Total contractual cash obligations *(c)*	$23,008,459	$3,434,516	$4,640,990	$3,945,531	$10,987,422

(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, 2004, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $130.5 million.

(b) Obligations to purchase fuel for electric generating plants, and electricity and natural gas for resale. Certain contractual purchase obligations are adjusted based on indexes. However, the effects of price changes are mitigated through cost-of-energy adjustment mechanisms.

(c) Xcel Energy also has outstanding authority under contracts and blanket purchase orders to purchase up to approximately $500 million of goods and services through the year 2020, in addition to the amounts disclosed in this table and in the forecasted capital expenditures.

Common Stock Dividends Future dividend levels will be dependent upon the statutory limitations discussed below, as well as 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 deliver the financial results that will enable the board of directors to grant annual dividend increases at a rate consistent with our long-term earnings growth rate. Xcel Energy's dividend policy balances:
- projected cash generation from utility operations;
- projected capital investment in the utility businesses;
- reasonable rate of return on shareholder investment; and
- impact on Xcel Energy's capital structure and credit ratings.

Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Xcel Energy had $397 million of retained earnings at Dec. 31, 2004, and expects to declare dividends as scheduled. The cash to pay dividends to Xcel Energy shareholders is primarily derived from dividends received from the utility subsidiaries. The utility subsidiaries are generally limited in the amount of dividends allowed by state regulatory commissions to be paid to the holding company. The limitation is imposed through equity ratio limitations that range from 30 percent to 60 percent. All utility subsidiaries are required under PUHCA to pay dividends only from retained earnings, and some must comply with covenant 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, i.e., not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to common stock plus surplus divided by the sum of common stock plus surplus plus long-term debt. Based on this definition, Xcel Energy's capitalization ratio at Dec. 31, 2004, was 80 percent. 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.

Capital Sources

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

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, are limited under PUHCA in their ability to issue securities. Such registered holding companies and their subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy does not qualify for any of the main exemptive rules, it has received financing authority from the SEC under PUHCA for various financing arrangements. Xcel Energy's current financing authority permits it, subject to satisfaction of certain conditions, to issue through June 30, 2005, up to $2.5 billion of common stock and long-term debt and $1.5 billion of short-term debt at the holding-company level. Xcel Energy has issued $2.2 billion of long-term debt and common stock, including the $600 million credit facility that closed in November 2004 that replaced the previous $400 million facility.

On Dec. 17, 2004, Xcel Energy filed an application with the SEC requesting additional financing authorization beyond June 30, 2005. If approved, the new financing authority would extend through June 30, 2008. The new application requests the authority for Xcel Energy to issue up to $1.8 billion of new long-term debt, common equity and equity-linked securities and $1.0 billion of short-term debt securities during the new authorization period, provided that the aggregate amount of long-term debt, common equity, equity-linked and short-term debt securities issued during the new authorization period does not exceed $2.0 billion. Xcel Energy expects the SEC to issue an order prior to the expiration of the existing authorization.

Xcel Energy's ability to issue securities under the financing authority is subject to a number of conditions. One of the conditions of the financing authority is that Xcel Energy's consolidated ratio of common equity to total capitalization be at least 30 percent. As of Dec. 31, 2004, the common equity ratio was approximately 42 percent. Additional conditions require that a security to be issued that is rated, be rated investment grade by at least one nationally recognized rating agency. Finally, all outstanding securities that are rated must be rated investment grade by at least one nationally recognized rating agency. On Feb. 17, 2005, Xcel Energy's senior unsecured debt was considered investment grade by Standard & Poor's Ratings Services (Standard & Poor's) and Moody's Investors Services, Inc. (Moody's).

Short-Term Funding Sources Historically, Xcel Energy has used a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures. Another significant short-term funding need is the dividend payment.

As of Feb. 17, 2005, Xcel Energy and its utility subsidiaries had the following credit facilities available to meet its liquidity needs:

(Millions of dollars)	*Facility*	*Drawn**	*Available*	*Cash*	*Liquidity*	*Maturity*
NSP-Minnesota	$ 300	$ 84	$216	$ –	$216	May 2005**
NSP-Wisconsin	–	–	–	–	–	
PSCo	350	151	199	29	228	May 2005**
SPS	125	68	57	–	57	May 2005**
Xcel Energy – holding company	600	160	440	2	442	November 2009
Total	$1,375	$463	$912	$31	$943	

** Includes short-term borrowings and letters of credit.*

*** The credit facilities of NSP-Minnesota, PSCo and SPS are expected to be renewed as five-year revolving credit facilities through a pro-rata syndication prior to May 2005.*

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 and industry deregulation; changes in the trends for energy prices; and supply and operational uncertainties, 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. 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 and Standard & Poor's. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating company. As of Feb. 17, 2005, the following represents the credit ratings assigned to various Xcel Energy companies:

Company	*Credit Type*	*Moody's*	*Standard & Poor's*
Xcel Energy	Senior Unsecured Debt	Baa1	BBB-
Xcel Energy	Commercial Paper	NP	A2
NSP-Minnesota	Senior Unsecured Debt	A3	BBB-
NSP-Minnesota	Senior Secured Debt	A2	A-
NSP-Minnesota	Commercial Paper	P2	A2
NSP-Wisconsin	Senior Unsecured Debt	A3	BBB
NSP-Wisconsin	Senior Secured Debt	A2	A-
PSCo	Senior Unsecured Debt	Baa1	BBB-
PSCo	Senior Secured Debt	A3	A-
PSCo	Commercial Paper	P2	A2
SPS	Senior Unsecured Debt	Baa1	BBB
SPS	Commercial Paper	P2	A2

Note: Moody's highest credit rating for debt is Aaa1 and lowest investment grade rating is Baa3. Standard & Poor's highest credit rating for debt is AAA+ and lowest investment grade rating is BBB-. Moody's prime ratings for commercial paper range from P1 to P3. NP denotes a nonprime rating. Standard & Poor's ratings for commercial paper range from A1 to A3, B and C. As of Feb. 17, 2005, Moody's had Xcel Energy and its operating utility subsidiaries on "stable outlook." Standard & Poor's also had Xcel Energy and its operating utility subsidiaries on "stable outlook."

In the event of a downgrade of its credit ratings 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 15 to the Consolidated Financial Statements. Xcel Energy has no explicit rating triggers in its debt agreements.

Money Pool In 2003, Xcel Energy established a money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The 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 money pool arrangement does not allow loans from the utility subsidiaries to the holding company. State regulatory commission approvals have been received for NSP-Minnesota, PSCo and SPS, and borrowing and lending activity for these utilities has commenced. On Jan. 18, 2005, NSP-Wisconsin submitted a letter to the Public Service Commission of Wisconsin (PSCW) withdrawing its request for approval to participate in the money pool arrangement after it became apparent the conditions likely to be imposed by the PSCW would have limited flexibility and reduced the economic benefits of NSP-Wisconsin's participation. The borrowings or loans outstanding at Dec. 31, 2004, and the SEC approved short-term borrowing limits from the utility money pool are:

	Borrowings (Loans)	*Total Borrowing Limits*
NSP-Minnesota	–	$250 million
PSCo	–	$250 million
SPS	–	$100 million

Registration Statements Xcel Energy's Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of Dec. 31, 2004, Xcel Energy had approximately 400 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, 2004, 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:

- In February 2002, Xcel Energy filed a $1 billion shelf registration with the SEC. Xcel Energy may issue debt securities, common stock and rights to purchase common stock under this shelf registration. Xcel Energy has approximately $482.5 million remaining under this registration. Xcel Energy has approximately $400 million remaining under the $1 billion shelf registration filed with the SEC in 2000.
- In April 2001, NSP-Minnesota filed a $600 million, long-term debt shelf registration with the SEC. NSP-Minnesota has approximately $40 million remaining under this registration.
- PSCo has an effective shelf registration statement with the SEC under which $800 million of secured first collateral trust bonds or unsecured senior debt securities were registered. PSCo has approximately $225 million remaining under this registration.

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments primarily through internally generated funds. Xcel Energy plans to renew its credit facilities at NSP-Minnesota, PSCo and SPS during 2005 and may refinance existing long-term debt or scheduled long-term debt maturities based on prevailing market conditions. The renewal of the credit facilities at NSP-Minnesota, PSCo and SPS is planned to be done with long-term credit facilities for which borrowings would be reflected as a long-term liability on the consolidated balance sheet. To facilitate its potential debt issuances, NSP-Minnesota may file a long-term debt shelf registration statement with the SEC for up to $1 billion in 2005.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements 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 2005 earnings per share (EPS) from continuing operations guidance and key assumptions are detailed in the following table.

	2005 Diluted EPS Range
Utility operations	$1.27–$1.37
Holding company financing costs	(0.11)
Other nonregulated subsidiaries	0.02
Xcel Energy Continuing Operations – EPS	$1.18–$1.28

Key assumptions for 2005:

- Seren is held for sale and accounted for as discontinued operations;
- Normal weather patterns are experienced for 2005;
- Weather-adjusted retail electric utility sales growth of approximately 2.0 percent to 2.4 percent;
- Weather-adjusted retail natural gas utility sales growth of approximately 1.0 percent to 1.3 percent;
- A successful outcome in the $9.9 million NSP-Minnesota gas rate case;
- A successful outcome in the FERC rate case of approximately $5 million;
- Capacity costs are projected to increase by $15 million, net of capacity cost recovery;
- No additional margin impact associated with the fuel allocation issue at SPS;
- 2005 trading and short-term wholesale margins are projected to decline by approximately $30 million to $55 million;
- 2005 other utility operating and maintenance expense is expected to increase between 2 percent to 3 percent;
- 2005 depreciation expense is projected to increase approximately 7 percent to 8 percent;
- 2005 interest expense is projected to increase approximately $10 million to $15 million;
- Allowance for funds used during construction-equity is projected to be relatively flat;
- Xcel Energy continues to recognize COLI tax benefits of 9 cents per share in 2005;
- The effective tax rate for continuing operations is expected to be approximately 28 percent to 31 percent; and
- Average common stock and equivalents of approximately 426 million shares in 2005, based on the "If Converted" method for convertible notes.

MANAGEMENT REPORT ON INTERNAL CONTROLS

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, 2004. 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, 2004, 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 our assessment of the company's internal control over financial reporting. Their report appears on the following page.

Wayne H. Brunetti
Chairman and Chief Executive Officer
March 3, 2005

Benjamin G.S. Fowke III
Vice President and Chief Financial Officer
March 3, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders of Xcel Energy Inc.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. (a Minnesota Corporation) and subsidiaries (the "Company") as of December 31, 2004 and 2003, and the related consolidated statements of operations, common stockholders' equity and other comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the consolidated statements of operations, stockholders (deficit) equity and cash flows of NRG Energy, Inc. (a wholly owned subsidiary of Xcel Energy Inc.) included in the consolidated financial statements of the Company, which statements reflect losses from discontinued operations net of tax of $3.5 billion for the year ended December 31, 2002. Such financial statements were audited by other auditors whose report has been furnished to us (which as to 2002 expresses an unqualified opinion and includes an explanatory paragraph describing conditions that raise substantial doubt about NRG Energy, Inc.'s ability to continue as a going concern), and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. for the period described above, is based solely on the report of such other auditors.

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 misstatements. 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, based on our audits and the report of other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

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, 2004, 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 March 3, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting based on our audits.

Deloitte & Touche LLP

Minneapolis, Minnesota
March 3, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Xcel Energy Inc.

We have audited management's assessment, included in the accompanying *Management Report On Internal Controls*, that Xcel Energy Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, 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 as of December 31, 2004 of the Company and subsidiaries and our report dated March 3, 2005 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Minneapolis, Minnesota
March 3, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder's (deficit)/equity (not presented separately herein) present fairly, in all material respects, the results of operations and cash flows of NRG Energy, Inc. and its subsidiaries for the year ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with standards of the Public Company Accounting Oversight Board (United States) of America. 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, assessing the accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

The consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 and Note 29 to the consolidated financial statements, the Company is experiencing credit and liquidity constraints and has various credit arrangements that are in default. As a direct consequence, during 2002 the Company entered into discussions with its creditors to develop a comprehensive restructuring plan. In connection with its restructuring efforts, the Company and certain of its subsidiaries filed for Chapter 11 bankruptcy protection. These conditions raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
March 28, 2003, except as to Notes 29 and 30, which are as of December 3, 2003.

(Thousands of dollars, except per share data)	***2004***	*Year ended Dec. 31* *2003*	*2002*
Operating revenues			
Electric utility	**$6,260,938**	$5,951,852	$ 5,422,498
Natural gas utility	**1,923,526**	1,685,346	1,340,699
Nonregulated and other	**160,795**	221,807	211,048
Total operating revenues	**8,345,259**	7,859,005	6,974,245
Operating expenses			
Electric fuel and purchased power – utility	**3,040,759**	2,705,839	2,197,801
Cost of natural gas sold and transported – utility	**1,445,773**	1,190,996	837,702
Cost of sales – nonregulated and other	**83,394**	142,540	109,535
Other operating and maintenance expenses – utility	**1,592,564**	1,570,492	1,480,955
Other operating and maintenance expenses – nonregulated	**56,425**	70,216	91,421
Depreciation and amortization	**708,474**	728,992	746,561
Taxes (other than income taxes)	**327,029**	317,878	317,247
Special charges (see Note 2)	**17,625**	19,039	19,265
Total operating expenses	**7,272,043**	6,745,992	5,800,487
Operating income	**1,073,216**	1,113,013	1,173,758
Interest and other income, net of nonoperating expenses (see Note 13)	**14,808**	10,101	36,803
Allowance for funds used during construction – equity	**33,648**	25,338	7,793
Interest charges and financing costs			
Interest charges – (includes other financing costs of $27,296, $32,087 and $34,834, respectively)	**458,971**	448,882	400,709
Allowance for funds used during construction – debt	**(23,814)**	(20,402)	(17,933)
Distributions on redeemable preferred securities of subsidiary trusts	**–**	22,731	38,344
Total interest charges and financing costs	**435,157**	451,211	421,120
Income from continuing operations before income taxes	**686,515**	697,241	797,234
Income taxes	**159,586**	171,401	245,846
Income from continuing operations	**526,929**	525,840	551,388
Income (loss) from discontinued operations – net of tax (see Note 3)	**(170,968)**	96,552	(2,769,379)
Net income (loss)	**355,961**	622,392	(2,217,991)
Dividend requirements on preferred stock	**4,241**	4,241	4,241
Earnings (loss) available to common shareholders	**$ 351,720**	$ 618,151	$(2,222,232)
Weighted average common shares outstanding (in thousands)			
Basic	**399,456**	398,765	382,051
Diluted	**423,334**	418,912	384,646
Earnings (loss) per share – basic			
Income from continuing operations	**$ 1.31**	$ 1.31	$ 1.43
Income (loss) from discontinued operations (see Note 3)	**(0.43)**	0.24	(7.25)
Earnings (loss) per share	**$ 0.88**	$ 1.55	$ (5.82)
Earnings (loss) per share – diluted			
Income from continuing operations	**$ 1.27**	$ 1.27	$ 1.43
Income (loss) from discontinued operations (see Note 3)	**(0.40)**	0.23	(7.20)
Earnings (loss) per share	**$ 0.87**	$ 1.50	$ (5.77)

See Notes to Consolidated Financial Statements.

	Year ended Dec. 31		
(Thousands of dollars)	***2004***	*2003*	*2002*
Operating activities			
Net (loss) income	**$ 355,961**	$622,392	$(2,217,991)
Remove (income) loss from discontinued operations	**170,968**	(96,552)	2,769,379
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	**741,544**	759,523	768,250
Nuclear fuel amortization	**43,296**	43,401	48,675
Deferred income taxes	**45,488**	101,672	143,880
Amortization of investment tax credits	**(12,189)**	(12,439)	(13,212)
Allowance for equity funds used during construction	**(33,648)**	(25,338)	(7,793)
Undistributed equity in earnings of unconsolidated affiliates	**(5,379)**	(5,628)	5,774
Write-downs and losses from investments	**–**	8,856	15,866
Unrealized gain (loss) on derivative financial instruments	**5,794**	(1,954)	17,779
Change in accounts receivable	**(123,257)**	(126,786)	21,214
Change in inventories	**(46,185)**	(994)	(30,555)
Change in other current assets	**(188,935)**	(167,051)	111,947
Change in accounts payable	**129,171**	106,576	(131,716)
Change in other current liabilities	**5,707**	(10,524)	(133,693)
Change in other noncurrent assets	**(5,391)**	(133,025)	(224,153)
Change in other noncurrent liabilities	**42,948**	45,096	138,521
Operating cash flows provided by (used in) discontinued operations	**(308,788)**	270,761	432,939
Net cash provided by operating activities	**817,105**	1,377,986	1,715,111
Investing activities			
Utility capital/construction expenditures	**(1,274,290)**	(944,421)	(903,974)
Allowance for equity funds used during construction	**33,648**	25,338	7,793
Investments in external decommissioning fund	**(80,582)**	(80,581)	(57,830)
Nonregulated capital expenditures and asset acquisitions	**(2,160)**	(12,611)	(3,488)
Equity investments, loans, deposits and sales of nonregulated projects	**(4,082)**	13,300	(17,253)
Restricted cash	**42,628**	(38,488)	(23,000)
Other investments	**12,588**	1,106	7,040
Investing cash flows provided by (used in) discontinued operations	**37,043**	110,261	(1,720,614)
Net cash used in investing activities	**(1,235,207)**	(926,096)	(2,711,326)
Financing activities			
Short-term borrowings – net	**253,737**	(445,080)	(867,466)
Proceeds from issuance of long-term debt	**138,848**	1,689,317	1,442,172
Repayment of long-term debt, including reacquisition premiums	**(157,595)**	(1,307,012)	(32,802)
Proceeds from issuance of common stock	**6,985**	3,219	69,488
Common stock repurchase	**(32,023)**	–	–
Dividends paid	**(320,444)**	(303,316)	(496,375)
Financing cash flows provided by (used in) discontinued operations	**(200)**	(4,000)	1,465,070
Net cash (used in) provided by financing activities	**(110,692)**	(366,872)	1,580,087
Net increase (decrease) in cash and cash equivalents	**(528,794)**	85,018	583,872
Net decrease in cash and cash equivalents – discontinued operations	**(13,167)**	(1,313)	(237,882)
Net increase in cash and cash equivalents – adoption of FIN No. 46	**3,439**	–	–
Cash and cash equivalents at beginning of year	**568,283**	484,578	138,588
Cash and cash equivalents at end of year	**$ 29,761**	$568,283	$ 484,578
Supplemental disclosure of cash flow information			
Cash paid for interest (net of amounts capitalized)	**$ 423,673**	$402,506	$ 640,628
Cash paid for income taxes (net of refunds received)	**$(355,639)**	$ (6,379)	$ 24,935

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2004	2003
Assets		
Current assets:		
Cash and cash equivalents	$ 29,761	$ 568,283
Restricted cash	–	37,363
Accounts receivable – net of allowance for bad debts: $34,694 and $30,899, respectively	769,302	646,638
Accrued unbilled revenues	435,431	367,005
Materials and supplies inventories – at average cost	162,150	162,140
Fuel inventory – at average cost	64,265	59,706
Natural gas inventories – at average cost as of Dec. 31, 2004; replacement cost in excess of LIFO: $73,197 as of Dec. 31, 2003 (see Note 1)	214,964	140,636
Recoverable purchased natural gas and electric energy costs	264,628	217,473
Derivative instruments valuation – at market	129,218	93,063
Prepayments and other	157,389	110,876
Current assets held for sale and related to discontinued operations	344,132	728,056
Total current assets	2,571,240	3,131,239
Property, plant and equipment, at cost:		
Electric utility plant	18,236,957	17,242,636
Natural gas utility plant	2,617,552	2,442,994
Common utility and other property	1,509,597	1,217,461
Construction work in progress	721,335	917,530
Total property, plant and equipment	23,085,441	21,820,621
Less accumulated depreciation	(9,063,794)	(8,605,082)
Nuclear fuel – net of accumulated amortization: $1,145,228 and $1,101,932, respectively	74,308	80,289
Net property, plant and equipment	14,095,955	13,295,828
Other assets:		
Investments in unconsolidated affiliates	79,386	124,462
Nuclear decommissioning fund and other investments	970,213	842,832
Regulatory assets	850,636	879,320
Derivative instruments valuation – at market	424,786	429,531
Prepaid pension asset	642,873	566,568
Other	179,592	206,870
Noncurrent assets held for sale and related to discontinued operations	490,162	728,730
Total other assets	3,637,648	3,778,313
Total assets	$20,304,843	$20,205,380
Liabilities and Equity		
Current liabilities:		
Current portion of long-term debt	$ 223,655	$ 159,955
Short-term debt	312,300	58,563
Accounts payable	906,308	774,336
Taxes accrued	211,901	193,895
Dividends payable	83,405	75,866
Derivative instruments valuation – at market	135,098	153,467
Other	366,771	411,435
Current liabilities held for sale and related to discontinued operations	96,556	843,549
Total current liabilities	2,335,994	2,671,066
Deferred credits and other liabilities:		
Deferred income taxes	2,071,914	1,991,483
Deferred investment tax credits	143,028	155,629
Regulatory liabilities	1,630,545	1,559,779
Derivative instruments valuation – at market	450,883	388,743
Asset retirement obligations	1,091,089	1,024,529
Customer advances	303,928	211,046
Minimum pension liability	62,669	54,647
Benefit obligations and other	328,627	310,355
Noncurrent liabilities held for sale and related to discontinued operations	82,028	72,549
Total deferred credits and other liabilities	6,164,711	5,768,760
Minority interest in subsidiaries	3,220	281
Commitments and contingencies (see Note 16)		
Capitalization (see Statements of Capitalization):		
Long-term debt	6,493,020	6,493,853
Preferred stockholders' equity	104,980	104,980
Common stockholders' equity	5,202,918	5,166,440
Total liabilities and equity	$20,304,843	$20,205,380

See Notes to Consolidated Financial Statements.

(Thousands)	*Common Stock Issued* Shares	Par Value	Capital in Excess of Par Value	*Retained Earnings (Deficit)*	*Shares Held by ESOP*	*Accumulated Other Comprehensive Income (Loss)*	*Total Stockholders' Equity*
Balance at Dec. 31, 2001	345,801	$ 864,503	$2,969,589	$2,558,403	$(18,564)	$(179,454)	$ 6,194,477
Net loss				(2,217,991)			(2,217,991)
Currency translation adjustments						30,008	30,008
Minimum pension liability						(107,782)	(107,782)
Net derivative instrument fair value changes during the period (see Note 14)						(39,475)	(39,475)
Unrealized loss – marketable securities						(457)	(457)
Comprehensive loss for 2002							(2,335,697)
Dividends declared:							
Cumulative preferred stock				(4,241)			(4,241)
Common stock				(437,113)			(437,113)
Issuances of common stock	27,148	67,870	513,342				581,212
Acquisition of NRG minority common shares	25,765	64,412	555,220			28,150	647,782
Repayment of ESOP loan					18,564		18,564
Balance at Dec. 31, 2002	398,714	$ 996,785	$4,038,151	$ (100,942)	$ –	$(269,010)	$ 4,664,984
Net income				622,392			622,392
Currency translation adjustments						182,829	182,829
Minimum pension liability						9,710	9,710
Net derivative instrument fair value changes during the period (see Note 14)						(14,005)	(14,005)
Unrealized gain – marketable securities						340	340
Comprehensive income for 2003							801,266
Dividends declared:							
Cumulative preferred stock			(720)	(3,181)			(3,901)
Common stock			(149,521)	(149,606)			(299,127)
Issuances of common stock	251	627	2,591				3,218
Balance at Dec. 31, 2003	398,965	$ 997,412	$3,890,501	$ 368,663	$ –	$ (90,136)	$ 5,166,440
Net income				355,961			355,961
Currency translation adjustments						(3)	(3)
Minimum pension liability						(7,935)	(7,935)
Net derivative instrument fair value changes during the period (see Note 14)						(8,024)	(8,024)
Unrealized gain – marketable securities						164	164
Comprehensive income for 2004							340,163
Dividends declared:							
Cumulative preferred stock				(4,241)			(4,241)
Common stock				(323,742)			(323,742)
Issuances of common stock	3,297	8,243	48,078				56,321
Purchase for restricted stock issuance	(1,800)	(4,500)	(27,523)				(32,023)
Balance at Dec. 31, 2004	**400,462**	**$1,001,155**	**$3,911,056**	**$ 396,641**	**$ –**	**$ (105,934)**	**$5,202,918**

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2004	2003
LONG-TERM DEBT		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Dec. 1, 2005–2006, 4%–4.1%	**$ 4,750** *(a)*	$ 6,990 *(a)*
Dec. 1, 2005, 6.125%	**70,000**	70,000
Aug. 1, 2006, 2.875%	**200,000**	200,000
Aug. 1, 2010, 4.75%	**175,000**	175,000
Aug. 28, 2012, 8%	**450,000**	450,000
March 1, 2019, 8.5%	**27,900** *(b)*	27,900 *(b)*
Sept. 1, 2019, 8.5%	**100,000** *(b)*	100,000 *(b)*
July 1, 2025, 7.125%	**250,000**	250,000
March 1, 2028, 6.5%	**150,000**	150,000
April 1, 2030, 8.5%	**69,000** *(b)*	69,000 *(b)*
Dec. 1, 2005–2008, 4.4%–5%	**9,790** *(a)*	11,990 *(a)*
Senior Notes due Aug. 1, 2009, 6.875%	**250,000**	250,000
Retail Notes due July 1, 2042, 8%	**185,000**	185,000
Other	**367**	399
Unamortized discount – net	**(7,759)**	(8,721)
Total	**1,934,048**	1,937,558
Less current maturities	**74,685**	4,502
Total NSP-Minnesota long-term debt	**$1,859,363**	$1,933,056
PSCo		
First Mortgage Bonds, Series due:		
March 1, 2004, 8.125%	**$ –**	$ 100,000
Nov. 1, 2005, 6.375%	**134,500**	134,500
June 1, 2006, 7.125%	**125,000**	125,000
April 1, 2008, 5.625%	**18,000** *(b)*	18,000 *(b)*
Oct. 1, 2008, 4.375%	**300,000**	300,000
June 1, 2012, 5.5%	**50,000** *(b)*	50,000 *(b)*
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
April 1, 2014, 5.875%	**61,500** *(b)*	61,500 *(b)*
Jan. 1, 2019, 5.1%	**48,750** *(b)*	48,750 *(b)*
Jan. 1, 2024, 7.25%	**110,000**	110,000
Unsecured Senior A Notes, due July 15, 2009, 6.875%	**200,000**	200,000
Secured Medium-Term Notes, due Feb. 2, 2004–March 5, 2007, 6.9%–7.11%	**100,000**	145,000
Unamortized discount	**(5,870)**	(6,835)
Capital lease obligations, 11.2% due in installments through 2028	**48,935**	47,650
Total	**2,315,815**	2,458,565
Less current maturities	**135,854**	147,131
Total PSCo long-term debt	**$2,179,961**	$2,311,434
SPS		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	**$ 100,000**	$ 100,000
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	**500,000**	500,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	**100,000**	100,000
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	**44,500**	44,500
July 1, 2016, 2% at Dec. 31, 2004, and 1.25% at Dec. 31, 2003	**25,000**	25,000
Sept. 1, 2016, 5.75% series	**57,300**	57,300
Unamortized discount	**(1,338)**	(1,653)
Total SPS long-term debt	**$ 825,462**	$ 825,147

See Notes to Consolidated Financial Statements.

(Thousands of dollars)	Dec. 31 2004	2003
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
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6%	**18,600** *(a)*	18,600 *(a)*
Fort McCoy System Acquisition, due Oct. 31, 2030, 7%	**862**	895
Senior Notes – due, Oct. 1, 2008, 7.64%	**80,000**	80,000
Unamortized discount	**(985)**	(1,051)
Total	**313,477**	313,444
Less current maturities	**34**	34
Total NSP-Wisconsin long-term debt	**$ 313,443**	$ 313,410
Other Subsidiaries		
Various Eloigne Co. Affordable Housing Project Notes, due 2005–2039, 0.3%–10%	**$ 110,412**	$ 39,139
Other	**9,830**	12,140
Total	**120,242**	51,279
Less current maturities	**13,082**	8,288
Total other subsidiaries long-term debt	**$ 107,160**	$ 42,991
Xcel Energy Inc.		
Unsecured senior notes, Series due:		
July 1, 2008, 3.4%	**$ 195,000**	$ 195,000
Dec. 1, 2010, 7%	**600,000**	600,000
Convertible notes, Series due:		
Nov. 21, 2007, 7.5%	**230,000**	230,000
Nov. 21, 2008, 7.5%	**57,500**	57,500
Borrowings under credit facility, due November 2009, 3.09%	**140,000**	–
Fair value hedge, carrying value adjustment	**(8,333)**	(6,298)
Unamortized discount	**(6,536)**	(8,387)
Total Xcel Energy Inc. debt	**$1,207,631**	$1,067,815
Total long-term debt from continuing operations	**$6,493,020**	$6,493,853
Long-Term Debt from Discontinued Operations		
First Mortgage Bonds – Cheyenne:		
Due Jan. 1, 2024, 7.5%	**$ 7,800**	$ 8,000
Industrial Development Revenue Bonds, due Sept. 1, 2021–March 1, 2027, variable rate, 2.12% and 1.3% at Dec. 31, 2004 and 2003, respectively	**17,000**	17,000
Total long-term debt from discontinued operations	**$ 24,800**	$ 25,000
Cumulative Preferred Stock – authorized 7,000,000 shares of $100 par value; outstanding shares: 2004: 1,049,800; 2003: 1,049,800		
$3.60 series, 275,000 shares	**$ 27,500**	$ 27,500
$4.08 series, 150,000 shares	**15,000**	15,000
$4.10 series, 175,000 shares	**17,500**	17,500
$4.11 series, 200,000 shares	**20,000**	20,000
$4.16 series, 99,800 shares	**9,980**	9,980
$4.56 series, 150,000 shares	**15,000**	15,000
Total preferred stockholders' equity	**$ 104,980**	$ 104,980
Common Stockholders' Equity		
Common stock – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2004: 400,461,804; 2003: 398,964,724	**$1,001,155**	$ 997,412
Capital in excess of par value on common stock	**3,911,056**	3,890,501
Retained earnings	**396,641**	368,663
Accumulated other comprehensive income (loss)	**(105,934)**	(90,136)
Total common stockholders' equity	**$5,202,918**	$5,166,440

(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. Xcel Energy and its subsidiaries are subject to the regulatory provisions of the PUHCA. The utility subsidiaries are subject to regulation by the FERC and state utility commissions. All of the utility companies' accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material respects.

Principles of Consolidation In 2004, Xcel Energy continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in 10 states. These utility subsidiaries are NSP-Minnesota; NSP-Wisconsin; PSCo and SPS. These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wisconsin. Along with WGI, an interstate natural gas pipeline, these companies comprise our continuing regulated utility operations. Discontinued utility operations include the activity of Viking, an interstate natural gas pipeline company that was sold in January 2003; BMG, a regulated natural gas and propane distribution company that was sold in October 2003; and Cheyenne, a regulated electric and natural gas utility that was sold in January 2005. See Note 3 to the Consolidated Financial Statements for more information on the discontinued operations of Viking, BMG and Cheyenne.

Xcel Energy's nonregulated subsidiaries in continuing operations include Utility Engineering Corp. (engineering, construction and design) and Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits). During 2003, Planergy International, Inc. (energy management solutions) closed and began selling a majority of its business operations, with final dissolution occurring in 2004.

During 2004, Xcel Energy's board of directors approved management's plan to pursue the sale of Seren Innovations, Inc. (broadband communications services). NRG, Xcel Energy International, e prime and Seren are presented as components of discontinued operations. During 2003, Xcel Energy also divested its ownership interest in NRG, an independent power producer. On May 14, 2003, NRG filed for bankruptcy to restructure its debt. As a result of the reorganization, Xcel Energy relinquished its ownership interest in NRG. During 2003, the board of directors of Xcel Energy also approved management's plan to exit businesses conducted by the nonregulated subsidiaries Xcel Energy International and e prime. See Note 3 to the Consolidated Financial Statements.

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

In 2004, Xcel Energy began consolidating the financial statements of subsidiaries in which it has a controlling financial interest, pursuant to the requirements of FASB Interpretation No. 46, as revised (FIN No. 46). Historically, consolidation has been required only for subsidiaries in which an enterprise has a majority voting interest. As a result, Xcel Energy is required to consolidate a portion of its affordable housing investments made through Eloigne, which for periods prior to 2004 are accounted for under the equity method. As of Dec. 31, 2004, the assets of the affordable housing investments consolidated as a result of FIN No. 46, as revised, were approximately $144 million and long-term liabilities were approximately $78 million, including long-term debt of $75 million. Investments of $51 million, previously reflected as a component of investments in unconsolidated affiliates, have been consolidated with the entities' assets initially recorded at their carrying amounts as of Jan. 1, 2004. The long-term debt is collateralized by the affordable housing projects and is nonrecourse to Xcel Energy.

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 significant 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 9 to the Consolidated Financial Statements.

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

Xcel Energy's utility subsidiaries have various rate-adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost-adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. In addition, Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees. A summary of significant rate-adjustment mechanisms follows:

– In 2004, PSCo generally recovered all prudently incurred electric fuel and purchased energy costs through an electric commodity adjustment clause. This fuel mechanism also has in place a sharing among customers and shareholders of certain fuel and energy costs, with an $11.25 million maximum on any cost sharing over or under an allowed electric commodity adjustment formula rate, and a sharing among shareholders and customers of certain gains and losses on trading margins. In 2003, PSCo's electric rates permitted recovery of 100 percent of prudently incurred electric fuel and purchased energy expense. In 2002, PSCo's electric rates in Colorado were adjusted under an incentive cost-adjustment mechanism, which resulted in the sharing of cost increases and decreases with customers and sharing of trading margins.
– NSP-Minnesota's rates include a cost-of-fuel-and-energy and a cost-of-gas recovery mechanism allowing dollar-for-dollar recovery of the respective costs, which are trued-up on a two-month and annual basis, respectively.

– NSP-Wisconsin's rates include a cost-of-gas adjustment clause for purchased natural gas, but not for purchased electric energy or electric fuel. In Wisconsin, requests can be made for recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.
– In Colorado, PSCo operates under an electric performance-based regulatory plan, which provides for an annual earnings test. NSP-Minnesota and PSCo operate under various service standards, which could require customer refunds if certain criteria are not met. NSP-Minnesota and PSCo's rates include monthly adjustments for the recovery of conservation and energy-management program costs, which are reviewed annually.
– SPS' rates in Texas provide electric fuel and purchased energy cost recovery. In New Mexico, SPS also has a monthly fuel and purchased power cost-recovery factor.
– 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 Operations.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Pursuant to the JOA approved by the FERC, some of the commodity trading margins are apportioned to the other operating utilities of Xcel Energy. 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 results are recorded at fair market value in accordance with SFAS No. 133, as amended. In addition, commodity trading results include the impacts of any margin-sharing mechanisms. In 2003, Xcel Energy's board of directors designated e prime as held for sale. e prime had conducted natural gas commodity trading activities. Consequently, e prime financial results are presented as discontinued operations. For more information, see Note 3 to the Consolidated Financial Statements.

Derivative Financial Instruments Xcel Energy and its subsidiaries utilize a variety of derivatives, including commodity forwards, futures and options, index or fixed-price swaps and basis swaps, to mitigate market risk and to enhance our operations. For further discussion of Xcel Energy's risk management and derivative activities, see Note 14 to the Consolidated Financial Statements.

Property, Plant, Equipment and Depreciation Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Removal costs associated with non-legal obligations are reclassified from accumulated depreciation and reflected as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses. Property, plant and equipment also includes costs associated with the engineering design of future generating stations and other property held for future use.

Xcel Energy determines the depreciation of its plant by using the straight-line method, which spreads the original cost equally over the plant's useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.1 percent, 3.0 percent and 3.4 percent for the years ended Dec. 31, 2004, 2003 and 2002, respectively.

Allowance for Funds Used During Construction (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.

Decommissioning Xcel Energy accounts for the future cost of decommissioning, or retirement, of its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. The decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. The fair value of external nuclear decommissioning fund investments are estimated based on quoted market prices for those or similar investments. Unrealized gains or losses are deferred as regulatory assets or liabilities. In 2003, NSP-Minnesota adopted SFAS No. 143, which changed the accounting methodology for nuclear decommissioning costs. For more information on nuclear decommissioning and the impacts of adopting SFAS No. 143, see Note 17 to the Consolidated Financial Statements.

PSCo also previously operated a nuclear generating plant, which has been decommissioned and repowered using natural gas. PSCo's costs associated with decommissioning were deferred and are being amortized consistent with regulatory recovery.

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

Environmental Costs Environmental costs are recorded 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 based on an expectation 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 has the latitude to compensate for final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

Legal Costs Litigation settlements are recorded when it is probable Xcel Energy is liable for the costs and the liability can be reasonably estimated. Legal accruals are recorded net of insurance recovery. Legal costs related to settlements are not accrued, but expensed as incurred.

Income Taxes Xcel Energy and its domestic subsidiaries file consolidated federal income tax returns. NRG and its domestic subsidiaries were included in Xcel Energy's consolidated federal income tax returns prior to NRG's March 2001 public equity offering. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries were included in some, but not all, of these combined returns in 2002 and 2003. NRG will not be consolidated or combined in any of Xcel Energy's income tax returns after 2003.

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. In accordance with PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company.

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.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which are summarized in Note 18 to the Consolidated Financial Statements.

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, 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 or revised annually, if appropriate.

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

Restricted cash in 2003 consisted primarily of funds received from NRG to be used to collateralize in full existing agreements of Xcel Energy to indemnify NRG, which continued after the divestiture of NRG. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Inventory All inventory is recorded at average cost, with the exception of natural gas in underground storage at PSCo, which until 2004 was recorded using last-in-first-out pricing (LIFO). Effective Jan. 1, 2004, PSCo changed its method of accounting for the cost of stored natural gas for its local distribution operations from the LIFO pricing method to the average cost pricing method. This change in accounting was approved by the CPUC and was accounted for as a cumulative effect in accordance with the CPUC authorization. The average cost method has historically been used for pricing stored natural gas by both NSP-Minnesota and NSP-Wisconsin, as well as by PSCo for natural gas stored for use in its electric utility operations.

The cumulative effect of this change in accounting principle resulted in an increase to natural gas storage inventory and a corresponding decrease to the deferred natural gas cost accounts of approximately $36 million as of Jan. 1, 2004. Of this amount, $33 million related to current natural gas storage inventory and $3 million related to long-term natural gas storage inventory. As natural gas costs are 100 percent recoverable for PSCo's local natural gas distribution operations under PSCo's natural gas cost-adjustment mechanism, the cumulative effect of this change had no impact on net income or earnings per share. Prior period financial statements were not restated since the CPUC authorized this change effective Jan. 1, 2004. Under the natural gas cost-adjustment mechanism, the decrease in the cost of natural gas reduced rates to retail natural gas customers in Colorado during 2004.

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

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

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 18 to the Consolidated Financial Statements.

Stock-Based Employee Compensation Xcel Energy has several stock-based compensation plans. Those plans are accounted for using the intrinsic-value method. Compensation expense is not recorded for stock options because there is no difference between the market price and the purchase price at grant date. Compensation expense is recorded for restricted stock and stock units awarded to certain employees, which are held until the restriction lapses or the stock is forfeited. For more information on stock compensation impacts, see Note 11 to the Consolidated Financial Statements.

Intangible Assets Intangible assets with finite lives are amortized over their economic useful lives and periodically reviewed for impairment. Beginning in 2002, goodwill is no longer being amortized, but is tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value.

Xcel Energy's goodwill consisted primarily of project-related goodwill at Utility Engineering for 2004 and 2003. During 2004 and 2003, impairment testing resulted in write-downs to this goodwill of $0.8 million and $4.8 million, respectively.

Intangible assets with finite lives continue to be amortized, and the aggregate amortization expense recognized in both years ended Dec. 31, 2004 and 2003, were approximately $0.2 million and $0.2 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $0.1 million. Intangible assets consisted of the following:

	Dec. 31, 2004		*Dec. 31, 2003*	
(Millions of dollars)	***Gross Carrying Amount***	***Accumulated Amortization***	*Gross Carrying Amount*	*Accumulated Amortization*
Not amortized:				
Goodwill	**$2.7**	**$0.6**	$3.5	$0.6
Amortized:				
Trademarks	**$5.1**	**$0.8**	$5.1	$0.7
Prior service costs	**$4.6**	**$ –**	$5.8	$ –
Other (primarily project development costs in 2004 and franchises in 2003)	**$3.3**	**$1.4**	$2.3	$0.6

Asset Valuation On Jan. 1, 2002, Xcel Energy adopted SFAS No. 144 – "Accounting for the Impairment or Disposal of Long-Lived Assets," which supercedes previous guidance for measurement of asset impairments. Xcel Energy did not recognize any asset impairments as a result of the adoption. The method used in determining fair value was based on a number of valuation techniques, including present value of future cash flows.

Deferred Financing Costs Other assets also included deferred financing costs, net of amortization, of approximately $44 million at Dec. 31, 2004. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Reclassifications Certain items in the statements of operations and the balance sheets have been reclassified from prior period presentation to conform to the 2004 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily related to organizational changes, such as the sale of Cheyenne and the planned divestiture of Seren and the related reclassification to discontinued operations.

2. SPECIAL CHARGES

Special charges included in Operating Expenses for the years ended Dec. 31, 2004, 2003 and 2002, include the following:

(Millions of dollars)	***2004***	*2003*	*2002*
Regulated utility special charges:			
Regulatory recovery adjustment (SPS)	**$ –**	$ –	$ 5
Restaffing (utility and service companies)	**–**	–	9
Total regulated utility special charges	**–**	–	14
Other nonregulated special charges:			
Holding company – NRG restructuring charges	**–**	12	5
Holding company – legal settlement	**18**	–	–
TRANSLink Transmission Co.	**–**	7	–
Total nonregulated special charges	**18**	19	5
Total special charges	**$18**	$19	$19

2004 Holding Company – Legal Settlement In 2004, Xcel Energy recorded a $17.6 million pretax charge for the accrual of a January 2005 settlement agreement related to shareholder lawsuits. For further discussion regarding the legal settlement, see Note 16 to the Consolidated Financial Statements.

2003 TRANSLink Transmission Co., LLC In 2003, Xcel Energy recorded a $7 million pretax charge in connection with the suspension of the activities related to the formation of TRANSLink. The charge was recorded as a reserve against loans made to TRANSLink Development Company, LLC, an interim start-up company. TRANSLink was an independent transmission-only company. The formation activity was suspended due to continued market and regulatory uncertainty.

2003 and 2002 Holding Company – NRG Restructuring Charges In 2003 and 2002, the Xcel Energy holding company incurred approximately $12 million and $5 million, respectively, for charges related to NRG's financial restructuring. Costs in 2003 included approximately $32 million of financial advisor fees, legal costs and consulting costs related to the NRG bankruptcy transaction. These charges were partially offset by a $20 million pension curtailment gain related to the termination of NRG employees from Xcel Energy's pension plan, as discussed in Note 12 to the Consolidated Financial Statements.

2002 Regulatory Recovery Adjustment – SPS During 2002, SPS entered into a settlement agreement with intervenors regarding the recovery of industry restructuring costs in Texas, which was approved by the state regulatory commission in May 2002. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million.

2002 Utility Restaffing During 2001, Xcel Energy expensed pretax special charges of $39 million for expected staff consolidation costs for an estimated 500 employees in several utility-operating and corporate-support areas of Xcel Energy. In 2002, the identification of affected employees was completed and additional pretax special charges of $9 million were expensed for the final costs of staff consolidations. Approximately $6 million of these restaffing costs were allocated to Xcel Energy's utility subsidiaries. All 564 of accrued staff terminations have occurred. See the summary of costs below.

Accrued Special Charges The following table summarizes activity related to accrued special charges related to the 2001 utility restaffing, as described above, for 2004, 2003 and 2002:

(Millions of dollars)	*Utility Severance**
Balance, Dec. 31, 2001	$37
Adjustments/revisions to prior year accruals	9
Cash payments made in 2002	(33)
Balance, Dec. 31, 2002	$13
Cash payments made in 2003	(10)
Balance, Dec. 31, 2003	$ 3
Cash payments made in 2004	(3)
Balance, Dec. 31, 2004	**$ –**

** Reported on the balance sheet in Other Current Liabilities.*

3. DISCONTINUED OPERATIONS

Pursuant to the requirements of SFAS No. 144, Xcel Energy classified and accounted for certain assets as held for sale at Dec. 31, 2004 and 2003. SFAS No. 144 requires that 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. In accordance with the provisions of SFAS No. 144, 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 on a net basis as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale in 2004 and 2003 have been reclassified to assets and liabilities held for sale accounts in the accompanying Balance Sheet.

Regulated Utility Segment

During 2003, Xcel Energy completed the sale of two subsidiaries in its regulated natural gas utility segment: Viking, including its interest in Guardian Pipeline, LLC, and BMG. After-tax disposal gains of $23.3 million, or 6 cents per share, were recorded for the natural gas utility segment, primarily related to the sale of Viking.

During January 2004, Xcel Energy reached an agreement to sell its regulated electric and natural gas subsidiary Cheyenne. Black Hills Corp. purchased all the common stock of Cheyenne, including the assumption of outstanding debt of approximately $25 million, for approximately $90 million, plus a working capital adjustment to be finalized in the second quarter of 2005. The sale was completed on Jan. 21, 2005, and resulted in an after-tax loss of approximately $13 million, or 3 cents per share, which was accrued at Dec. 31, 2004.

NRG Segment

Change in Accounting for NRG in 2003 Prior to NRG's bankruptcy filing in May 2003, Xcel Energy accounted for NRG as a consolidated subsidiary. However, as a result of NRG's bankruptcy filing, Xcel Energy no longer had the ability to control the operations of NRG. Accordingly, effective as of the bankruptcy filing date, Xcel Energy ceased the consolidation of NRG and began accounting for its investment in NRG using the equity method in accordance with Accounting Principles Board Opinion No. 18 – "The Equity Method of Accounting for Investments in Common Stock." After changing to the equity method, Xcel Energy was limited in the amount of NRG's losses subsequent to the bankruptcy date that it was required to record. In accordance with these limitations under the equity method, Xcel Energy stopped recognizing equity in the losses of NRG subsequent to the quarter ended June 30, 2003. These limitations provide for loss recognition by Xcel Energy until its investment in NRG is written off to zero, with further loss recognition to continue if its financial commitments to NRG exist beyond amounts already invested.

Prior to NRG entering bankruptcy, Xcel Energy recorded more losses than the limitations provide for as of June 30, 2003. Upon Xcel Energy's divestiture of its interest in NRG in December 2003, the NRG losses recorded in excess of Xcel Energy's investment in and financial commitment to NRG were reversed. This resulted in an adjustment of the total NRG losses recorded for the year 2003 to $251 million. Xcel Energy's share of NRG's results for all 2003 periods is reported in a single line item, Equity in Losses of NRG, as a component of discontinued operations. NRG's 2003 results do reflect some effects of asset impairments and restructuring costs, as discussed below. Xcel Energy's share of NRG results for 2002 was a loss of $3.4 billion, due primarily to asset impairments and other charges recorded in the third and fourth quarters of 2002 related to NRG's financial restructuring.

NRG Asset Impairments In 2002, NRG experienced credit-rating downgrades, defaults under numerous credit agreements, increased collateral requirements and reduced liquidity. These events resulted in impairment reviews of a number of NRG assets in 2002. NRG completed an analysis of the recoverability of the asset-carrying values of its projects each period, factoring in the probability weighting of different courses of action available to NRG, given its financial position and liquidity constraints at the time of each analysis. This approach was applied consistently to asset groups with similar uncertainties and cash flow streams. As a result, NRG determined that many of its construction projects and its operational projects became impaired during 2002 and 2003 and should be written down to fair market value. In applying those provisions, NRG management considered cash flow analyses, bids and offers related to those projects.

NRG incurred $3.5 billion of asset impairments and estimated disposal losses related to projects and equity investments, respectively, with lower expected cash flows or fair values. These charges recorded by NRG in the third and fourth quarters of 2002 included write-downs of $2.3 billion and $983 million for projects in development and operating projects, respectively, and $196 million for impairment charges and disposal losses related to equity investments.

Approximately $2.5 billion of these NRG impairment charges in 2002 related to NRG assets considered held for use under SFAS No. 144 as of Dec. 31, 2002. For fair values determined by similar asset prices, the fair value represented NRG's estimate of recoverability at that time, if the project assets were to be sold. For fair values determined by estimated market price, the fair value represented a market bid or appraisal received by NRG that NRG believed was best reflective of fair value at that time. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflected project-specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operation given assumed market conditions at that time.

NRG continued to incur asset impairments and related charges in 2003. Prior to its bankruptcy filing in May 2003, NRG recorded more than $500 million in impairment and related charges resulting from planned disposals of an international project and several projects in the United States, and to regulatory developments and changing circumstances throughout the second quarter that adversely affected NRG's ability to recover the carrying value of certain merchant generation units in the northeastern United States.

Nonregulated Subsidiaries – All Other Segment

On Sept. 27, 2004, Xcel Energy's board of directors approved management's plan to pursue the sale of Seren Innovations, Inc., a wholly owned broadband communications services subsidiary. Seren delivers cable television, high-speed Internet and telephone service over an advanced network to approximately 45,000 customers in St. Cloud, Minn., and Concord and Walnut Creek, Calif. An after-tax impairment charge, including disposition costs, of $143 million, or 34 cents per share, was recorded in 2004. Xcel Energy expects to complete the sale in mid-2005.

Xcel Energy International and e prime In December 2003, the board of directors of Xcel Energy approved management's plan to exit the businesses conducted by its nonregulated subsidiaries Xcel Energy International and e prime. The exit of all business conducted by e prime was completed in 2004.

Results of discontinued nonregulated operations in 2004 include the impact of the sale of the Argentina subsidiaries of Xcel Energy International. The sales took place in a series of three transactions with a total sales price of approximately $31 million. Approximately $15 million of the sales price was placed in escrow, which is expected to remain in place until at least the end of the first quarter of 2005, to support Xcel Energy's customary indemnity obligations under the sales agreement. In addition to the sales price, Xcel Energy also received approximately $21 million at the closing of one transaction as redemption of its capital investment. The sales resulted in a gain of approximately $8 million, including the realization of approximately $7 million of income tax benefits realizable upon sale of the Xcel Energy International assets.

Results of discontinued nonregulated operations in 2003, other than NRG, include an after-tax loss expected on the disposal of all Xcel Energy International assets of $59 million, based on the estimated fair value of such assets. The fair value represents a market bid or appraisal received that is believed to best reflect the assets' fair value at Dec. 31, 2003. Xcel Energy's remaining investment in Xcel Energy International at Dec. 31, 2003, was approximately $39 million. Losses from discontinued nonregulated operations in 2003 also include a charge of $16 million for costs of settling a Commodity Futures Trading Commission trading investigation of e prime.

Tax Benefits Related to Investment in NRG With NRG's emergence from bankruptcy in December 2003, Xcel Energy divested its ownership interest in NRG. Xcel Energy has recognized tax benefits related to the divestiture. These tax benefits, since related to Xcel Energy's investment in discontinued NRG operations, also are reported as discontinued operations.

During 2002, Xcel Energy recognized tax benefits of $706 million. This benefit was based on the estimated tax basis of Xcel Energy's cash and stock investments already made in NRG, and their deductibility for federal income tax purposes. Based on the results of a 2003 study, Xcel Energy recorded $105 million of additional tax benefits in 2003, reflecting an updated estimate of the tax basis of Xcel Energy's investments in NRG and state tax deductibility. Upon NRG's emergence from bankruptcy in December 2003, an additional $288 million of tax benefit was recorded to reflect the deductibility of the settlement payment of $752 million, uncollectible receivables from NRG, other state tax benefits and further adjustments to the estimated tax basis in NRG. Another $11 million of state tax benefits were accrued earlier in 2003 based on projected impacts. In 2004, the NRG basis study was completed and previously recognized tax benefits were reduced by $16 million.

Summarized Financial Results of Discontinued Operations

(Thousands of dollars)	*Utility Segment*	*NRG Segment*	*All Other Segment*	*Total*
2004				
Operating revenue	**$72,232**	**$ –**	**$ 89,167**	**$ 161,399**
Operating and other expenses	**68,305**	**–**	**106,198**	**174,503**
Special charges and impairments	**6,574**	**–**	**228,439**	**235,013**
Pretax income (loss) from operations of discontinued components	**(2,647)**	**–**	**(245,470)**	**(248,117)**
Income tax expense (benefit)	**6,388**	**–**	**(75,672)**	**(69,284)**
Income (loss) from operations of discontinued components	**(9,035)**	**–**	**(169,798)**	**(178,833)**
Estimated pretax gain on disposal of discontinued components	**–**	**–**	**961**	**961**
Income tax benefit	**–**	**–**	**6,904**	**6,904**
Gain on disposal of discontinued components	**–**	**–**	**7,865**	**7,865**
Net income (loss) from discontinued operations	**$ (9,035)**	**$ –**	**$(161,933)**	**$ (170,968)**
2003				
Operating revenue	$51,723	$ –	$ 210,304	$ 262,027
Operating and other expenses	46,539	–	246,017	292,556
Special charges and impairments	–	(1,664)	58,700	57,036
Equity in NRG losses	–	253,043	–	253,043
Pretax income (loss) from operations of discontinued components	5,184	(251,379)	(94,413)	(340,608)
Income tax expense (benefit)	1,667	–	(415,535)	(413,868)
Income (loss) from operations of discontinued components	3,517	(251,379)	321,122	73,260
Estimated pretax gain on disposal of discontinued components	40,072	–	–	40,072
Income tax expense	16,780	–	–	16,780
Gain on disposal of discontinued components	23,292	–	–	23,292
Net income (loss) from discontinued operations	$26,809	$ (251,379)	$ 321,122	$ 96,552
2002				
Operating revenue and equity in project income	$73,455	$ 3,010,557	$ 193,688	$ 3,277,700
Operating and other expenses	50,923	3,173,598	224,123	3,448,644
Special charges and impairments (including net disposal losses)	–	3,459,406	26,962	3,486,368
Pretax income (loss) from operations of discontinued components	22,532	(3,622,447)	(57,397)	(3,657,312)
Income tax expense (benefit)	8,742	(172,517)	(718,352)	(882,127)
Income (loss) from operations of discontinued components	13,790	(3,449,930)	660,955	(2,775,185)
Estimated pretax gain on disposal of discontinued components	–	2,814	–	2,814
Income tax benefit	–	(2,992)	–	(2,992)
Gain on disposal of discontinued components	–	5,806	–	5,806
Net income (loss) from discontinued operations	$13,790	$(3,444,124)	$ 660,955	$(2,769,379)

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

(Thousands of dollars)	***2004***	*2003*
Cash	**$ 26,828**	$ 39,995
Restricted Cash	**15,000**	–
Trade receivables – net	**16,326**	55,057
Deferred income tax benefits	**234,305**	580,626
Other current assets	**51,673**	52,378
Current assets	**344,132**	728,056
Property, plant and equipment – net	**135,541**	399,271
Deferred income tax benefits	**338,863**	314,670
Other noncurrent assets	**15,758**	14,789
Noncurrent assets	**490,162**	728,730
Current portion of long-term debt	**–**	–
Accounts payable – trade	**26,752**	68,056
NRG settlement payments	**–**	752,000
Other current liabilities	**69,804**	23,493
Current liabilities	**96,556**	843,549
Long-term debt	**24,800**	25,000
Minority interest	**–**	5,363
Other noncurrent liabilities	**57,228**	42,186
Noncurrent liabilities	**$ 82,028**	$ 72,549

4. NRG BANKRUPTCY

In June 2002, in response to NRG's severe financial difficulties, Xcel Energy completed an exchange transaction, whereby Xcel Energy acquired a 100-percent interest in NRG through a tender offer and merger involving a tax-free exchange of 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. Xcel Energy reacquired all of the 26 percent of NRG shares not then owned by Xcel Energy, which was accounted for as a purchase. The 25,764,852 shares of Xcel Energy stock issued were valued at $25.14 per share, based on the average market price of Xcel Energy shares for three days before and after April 4, 2002, when the revised terms of the exchange were announced and recommended by the independent members of the NRG board of directors. Including other costs of acquisition, this resulted in a total purchase price to acquire NRG's shares of approximately $656 million. The process to allocate the purchase price to underlying interests in NRG assets, and to determine fair values for the interests in assets acquired, resulted in approximately $62 million of amounts being allocated to fixed assets related to projects where the fair values were in excess of carrying values, to prepaid pension assets and to other assets.

The continued financial difficulties at NRG, resulting primarily from lower prices for power and declining credit ratings, culminated in NRG and certain of its affiliates filing, on May 14, 2003, voluntary petitions in the U.S. Bankruptcy Court for the Southern District of New York for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. In December 2003, NRG emerged from bankruptcy. As part of the reorganization, Xcel Energy completely relinquished its ownership interest in NRG. As part of the overall settlement, Xcel Energy agreed to pay $752 million to NRG to settle all claims of NRG against Xcel Energy, and claims of NRG creditors against Xcel Energy. In return for such payments, Xcel Energy received, or was granted, voluntary and involuntary releases from NRG and its creditors.

In 2004, Xcel Energy paid $752 million to NRG. Xcel Energy met these cash requirements with cash on hand, including tax refund proceeds associated with the NRG bankruptcy and/or borrowings under its revolving credit facility.

5. SHORT-TERM BORROWINGS

Credit Facilities As of Dec. 31, 2004, Xcel Energy had the following credit facilities available:

	Maturity	*Term*	*Credit Line*	*Available*
NSP-Minnesota	May 2005	364 days	$300 million	$171 million
PSCo	May 2005	364 days	$350 million	$153 million
SPS	February 2005	364 days	$125 million	$ 88 million
Other subsidiaries	Various	Various	$ 89 million	$ 77 million

The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and, depending on credit ratings, support for commercial paper borrowings. The borrowing rates under these lines of credit are based on either the bank's prime rate or the applicable London Interbank Offered Rate (LIBOR) plus a borrowing margin.

At Dec. 31, 2004 and 2003, Xcel Energy and its continuing subsidiaries had approximately $312 million and $59 million, respectively, in notes payable to banks, drawn on these credit lines. The weighted average interest rate at Dec. 31, 2004, was 4.15 percent. Also, $82.2 million of letters of credit were outstanding at Dec. 31, 2004, as discussed in Note 15 to the Consolidated Financial Statements, of which approximately $62.2 million were outstanding under the above credit facilities, which further reduced amounts available under the lines. Subsequent to Dec. 31, 2004, SPS arranged for the extension of the maturity date of its credit facility to May 2005.

6. LONG-TERM DEBT

Except for SPS, which does not currently have a first mortgage indenture, and other minor exclusions, all property of the utility subsidiaries is subject to the liens of their first mortgage indentures, which are contracts between the companies and their bondholders. In addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

The utility subsidiaries' first mortgage bond indentures provide for the ability to have sinking-fund requirements. NSP-Minnesota, NSP-Wisconsin and PSCo have no sinking-fund requirements for current bonds outstanding.

Xcel Energy has a $600 million, five-year senior unsecured revolving credit facility that matures in November 2009. Xcel Energy has the right to request a one-time increase in the size of the credit facility by up to $100 million and to request an extension of the final maturity date by one year. The maturity extension is subject to majority bank group approval. A financial covenant for debt to total capitalization is included. As of Dec. 31, 2004, Xcel Energy had $140 million drawn on this line of credit, which was classified as long-term debt. In addition, $82.2 million of letters of credit were outstanding at Dec. 31, 2004, as discussed in Note 15 to the Consolidated Financial Statements, of which $18.5 million were outstanding under the Xcel Energy credit facility, which further reduced the amount available under the line.

Xcel Energy's 2007 and 2008 series convertible senior notes are convertible into shares of Xcel Energy common stock at a conversion price of $12.33 per share. Conversion is at the option of the holder at any time prior to maturity. In addition, Xcel Energy must make additional payments of interest, referred to as protection payments, on the notes in an amount equal to any portion of regular quarterly per share dividends on common stock that exceeds $0.1875 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 20, 2004, the board of directors of Xcel Energy voted to raise the quarterly dividend on its common stock from $0.1875 to $0.2075. Consequently, as of Dec. 31, 2004, a total of $1.4 million in additional interest expense has been recorded.

In February 2005, PSCo redeemed $110 million of its 7.25-percent first collateral trust bonds, originally scheduled to mature in 2024.

Maturities of long-term debt are:

2005	$224 million
2006	$839 million
2007	$341 million
2008	$654 million
2009	$700 million

7. PREFERRED STOCK

At Dec. 31, 2004, Xcel Energy had six series of preferred stock outstanding, which were callable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends. Xcel Energy can only pay dividends on its preferred stock from retained earnings absent approval of the SEC under PUHCA. See Note 11 to the Consolidated Financial Statements for a description of such restrictions.

The holders of the $3.60 series preferred stock are entitled to three votes for each share held. The holders of the other preferred stocks 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 shares. However, at Dec. 31, 2004, there are no such shares outstanding. This chart shows data for first- and second-tier subsidiaries:

	Preferred Shares Authorized	*Par Value*	*Preferred Shares Outstanding*
Cheyenne*	1,000,000	$100.00	None
SPS	10,000,000	$ 1.00	None
PSCo	10,000,000	$ 0.01	None

** The sale of Cheyenne was completed in January 2005.*

8. MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS

Southwestern Public Service Capital I, a wholly owned, special-purpose subsidiary trust of SPS, had $100 million of 7.85-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2036. The securities were redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. On Oct. 15, 2003, SPS redeemed the $100 million of trust preferred securities. A certificate of cancellation was filed to dissolve SPS Capital I on Jan. 5, 2004.

NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, had $200 million of 7.875-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2037. The preferred securities were redeemable at NSP Financing I's option at $25 per share, beginning in 2002. On July 31, 2003, NSP-Minnesota redeemed the $200 million of trust preferred securities. A certificate of cancellation was filed to dissolve NSP Financing I on Sept. 15, 2003.

PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, had $194 million of 7.60-percent trust preferred securities issued and outstanding that were originally scheduled to mature in 2038. The securities were redeemable at the option of PSCo after May 2003, at 100 percent of the principal amount outstanding plus accrued interest. On June 30, 2003, PSCo redeemed the $194 million of trust preferred securities. A certificate of cancellation was filed to dissolve PSCo Capital Trust I on Dec. 29, 2003.

Distributions paid to preferred security holders were reflected as a financing cost in the Consolidated Statements of Operations, along with interest charges.

9. 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, 2004:

(Thousands of dollars)	*Plant in Service*	*Accumulated Depreciation*	*Construction Work in Progress*	*Ownership %*
NSP-Minnesota				
Sherco Unit 3	$492,581	$268,734	$2,244	59.0
Sherco Common Facilities Units 1, 2 and 3	102,556	50,428	–	65.6
Transmission facilities, including substations	4,832	1,765	–	59.0
Total NSP-Minnesota	$599,969	$320,927	$2,244	
PSCo				
Hayden Unit 1	$ 85,638	$ 42,839	$ –	75.5
Hayden Unit 2	79,979	45,094	443	37.4
Hayden Common Facilities	28,600	4,815	16	53.1
Craig Units 1 and 2	58,604	31,698	33	9.7
Craig Common Facilities Units 1, 2 and 3	32,553	9,547	18	6.5–9.7
Transmission and other facilities, including substations	150,812	41,171	359	11.6–73.0
Total PSCo	$436,186	$175,164	$ 869	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt, 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 components of operating expenses. PSCo's assets include approximately 320 megawatts of jointly owned generating capacity. PSCo's share of operating expenses and construction expenditures are included in the applicable utility components of operating expenses. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

Nuclear Plant Operation NSP-Minnesota and four other utility companies formed the Nuclear Management Co. (NMC), and each of the five member companies retains a 20 percent ownership interest in the NMC. The NMC is an operating company that manages the operations, maintenance and physical security of eight nuclear generating units on six sites, including three units/two sites owned by NSP-Minnesota. NSP-Minnesota continues to own the plants, controls all energy produced by the plants, and retains responsibility for nuclear property and liability insurance and decommissioning costs. In accordance with the Nuclear Power Plant Operating Services Agreement, NSP-Minnesota also pays its proportionate share of the operating expenses and capital improvement costs incurred by NMC. NSP-Minnesota paid NMC $314.7 million in 2004, $227.0 million in 2003 and $182.5 million in 2002.

10. INCOME TAXES

Xcel Energy's share of NRG results for current and prior periods is shown as a component of discontinued operations, due to NRG's emergence from bankruptcy in December 2003 and Xcel Energy's corresponding divestiture of its ownership interest in NRG. Accordingly, Xcel Energy's tax benefits related to its investment in NRG are reported in discontinued operations.

Xcel Energy's federal net operating loss and tax credit carry forwards are estimated to be $1.4 billion and $79 million, respectively. $1.2 billion of the net operating loss and $23 million of the tax credit carry forwards are accounted for in discontinued operations. The carry forward periods expire in 2023 and 2024. Xcel Energy also has a net operating loss carry forward in some states. The state carry forward periods expire between 2018 and 2024. A valuation allowance was recorded against $46 million of capital loss carry forwards related to the sales of Xcel Energy International subsidiaries, which are accounted for in discontinued operations. The capital loss carry forward period expires in 2009.

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:

	2004	2003	2002
Federal statutory rate	**35.0%**	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	**3.3**	2.2	3.2
Life insurance policies	**(4.0)**	(3.7)	(3.2)
Tax credits recognized	**(4.5)**	(4.0)	(4.5)
Regulatory differences – utility plant items	**(0.1)**	0.8	1.5
Resolution of income tax audits and prior period adjustments	**(5.3)**	(5.0)	–
Other – net	**(1.2)**	(0.7)	(1.2)
Effective income tax rate from continuing operations	**23.2%**	24.6%	30.8%

Income taxes comprise the following expense (benefit) items:

(Thousands of dollars)	2004	2003	2002
Current federal tax expense	**$108,857**	$126,828	$117,430
Current state tax expense (benefit)	**35,733**	(1,170)	22,149
Current tax credits	**(18,303)**	(15,268)	(19,079)
Deferred federal tax expense	**45,172**	70,153	124,537
Deferred state tax expense	**316**	3,298	17,435
Deferred investment tax credits	**(12,189)**	(12,440)	(16,626)
Total income tax expense from continuing operations	**$159,586**	$171,401	$245,846

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

(Thousands of dollars)	2004	2003
Deferred tax liabilities:		
Differences between book and tax bases of property	**$2,056,777**	$1,810,220
Regulatory assets	**244,388**	243,590
Employee benefits	**32,658**	102,142
Partnership income/loss	**22,374**	32,145
Service contracts	**11,369**	18,757
Other	**29,311**	29,016
Total deferred tax liabilities	**$2,396,877**	$2,235,870
Deferred tax assets:		
Net operating loss carry forward	**$ 90,187**	$ 28,846
Other comprehensive income	**63,876**	54,648
Deferred investment tax credits	**55,967**	61,070
Tax credit carry forward	**51,046**	11,668
Regulatory liabilities	**39,415**	44,284
Book reverses and other	**71,649**	36,698
Total deferred tax assets	**$ 372,140**	$ 237,214
Net deferred tax liability	**$2,024,737**	$1,998,656

11. COMMON STOCK AND INCENTIVE STOCK PLANS

Common Stock and Equivalents Xcel Energy has common stock equivalents consisting of convertible senior notes, restricted stock units and stock options, as discussed further.

The dilutive impacts of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

(Shares and dollars in thousands, except per share amounts)	**2004** Income	**2004** Shares	**2004** Per Share Amount	2003 Income	2003 Shares	2003 Per Share Amount	2002 Income	2002 Shares	2002 Per Share Amount
Income from continuing operations	**$526,929**			$525,840			$551,388		
Less: Dividend requirements on preferred stock	**(4,241)**			(4,241)			(4,241)		
Basic earnings per share									
Income from continuing operations	**522,688**	**399,456**	**$1.31**	521,599	398,765	$1.31	547,147	382,051	$1.43
Effect of dilutive securities:									
$230 million convertible debt	**11,940**	**18,654**		11,213	18,654		1,246	2,027	
$100 million convertible debt	**–**	**–**		–	–		–	445	
$57.5 million convertible debt	**2,985**	**4,663**		311	507		–	–	
Convertible debt option	**–**	**–**		–	508		–	–	
Restricted stock units	**–**	**544**		–	464		–	–	
Options	**–**	**17**		–	14		–	123	
Diluted earnings per share									
Income from continuing operations and assumed conversions	**$537,613**	**423,334**	**$1.27**	$533,123	418,912	$1.27	$548,393	384,646	$1.43

Incentive Stock Plans Xcel Energy and some of its subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate Xcel Energy's earnings per share include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables below include awards made by Xcel Energy and some of its predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

Activity in stock options was as follows for the years ended Dec. 31:

(Awards in thousands)	**2004** Awards	**2004** Average Price	2003 Awards	2003 Average Price	2002 Awards	2002 Average Price
Outstanding beginning of year	**15,614**	**$26.49**	16,981	$26.29	15,214	$25.65
Granted	**–**	**$ –**	–	$ –	–	$ –
Options transferred from NRG acquisition	**–**	**$ –**	–	$ –	3,328	$29.97
Exercised	**(45)**	**$15.08**	(190)	$12.21	(112)	$20.27
Forfeited	**(172)**	**$25.10**	(580)	$28.48	(1,349)	$28.43
Expired	**(791)**	**$24.08**	(597)	$23.41	(100)	$28.87
Outstanding at end of year	**14,606**	**$26.67**	15,614	$26.49	16,981	$26.29
Exercisable at end of year	**10,096**	**$26.58**	9,358	$25.59	8,933	$24.78

	Range of Exercise Prices $13.81 *to* $25.50	$25.51 *to* $27.00	$27.01 *to* $51.25
Options outstanding:			
Number outstanding	3,223,321	7,263,102	4,120,235
Weighted average remaining contractual life (years)	3.5	5.4	5.3
Weighted average exercise price	$20.47	$26.29	$32.20
Options exercisable:			
Number exercisable	3,223,321	4,212,102	2,660,135
Weighted average exercise price	$20.47	$26.27	$34.50

Certain employees also may elect to receive shares of restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock vests in equal annual installments over a three-year period from the date of grant. 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. Restricted stock has a value equal to the market-trading price of Xcel Energy's stock at the grant date. Xcel Energy granted 65,090 shares of restricted stock in 2004 when the grant-date market price was $17.40. Xcel Energy did not grant any shares of restricted stock in 2003. Xcel Energy granted 50,083 shares of restricted stock in 2002 when the grant-date market price was $22.83. Compensation expense related to these awards was not significant.

On March 28, 2003, the governance, compensation and nominating committee of Xcel Energy's board of directors granted restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan approved by the shareholders in 2000. Restrictions on the restricted stock units lapse upon the achievement of a 27-percent total shareholder return (TSR) for 10 consecutive business days and other criteria relating to Xcel Energy's common equity ratio. Under no circumstances will the restrictions lapse until one year after the grant date. TSR is measured using the market price per share of Xcel Energy common stock, which at the grant date was $12.93, plus common dividends declared after grant date. The TSR was met in the fourth quarter of 2003, and approximately $31 million of compensation expense was recorded at Dec. 31, 2003. The remaining cost of $10 million related to the 2003 restricted stock units was recorded in the first quarter of 2004. In January 2004, Xcel Energy's board of directors approved the repurchase of up to 2.5 million shares of common stock to fulfill the requirements of the restricted stock unit exercise. On March 29, 2004, the restricted stock units lapsed, and Xcel Energy issued approximately 1.6 million shares of common stock.

On Dec. 9, 2003, the governance, compensation and nominating committee of Xcel Energy's board of directors approved restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan. On Jan. 2, 2004, Xcel Energy granted 836,186 restricted stock units and performance shares. The grant-date market price used to calculate the TSR for this grant is $17.03. No expense has been recorded for the 2004 restricted stock units as it is not currently probable they will be earned.

On Dec. 14, 2004, the governance, compensation and nominating committee of Xcel Energy's board of directors approved restricted stock units and performance shares under the Xcel Energy Inc. Omnibus Incentive Plan. On Jan. 1, 2005, Xcel Energy granted 843,251 restricted stock units and performance shares. The grant-date market price used to calculate the TSR for this grant is $18.10.

Xcel Energy applies Accounting Principles Board Opinion No. 25 – "Accounting for Stock Issued to Employees" in accounting for stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options, as the exercise price of the options equals the fair-market value of Xcel Energy's common stock at the date of grant. In December 2002, the FASB issued SFAS No. 148 – "Accounting for Stock-Based Compensation – Transition and Disclosure," amending SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation, and requiring disclosure in both annual and interim Consolidated Financial Statements about the method used and the effect of the method used on results. The pro forma impact of applying SFAS No. 148 is as follows at Dec. 31:

(Thousands of dollars, except per share amounts)	***2004***	*2003*	*2002*
Net income (loss) – as reported	**$355,961**	$622,392	$(2,217,991)
Less: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	**(2,339)**	(3,897)	(6,959)
Pro forma net income (loss)	**$353,622**	$618,495	$(2,224,950)
Earnings (loss) per share:			
Basic – as reported	**$ 0.88**	$ 1.55	$ (5.82)
Basic – pro forma	**$ 0.87**	$ 1.54	$ (5.84)
Diluted – as reported	**$ 0.87**	$ 1.50	$ (5.77)
Diluted – pro forma	**$ 0.86**	$ 1.49	$ (5.79)

Common Stock Dividends Per Share Historically, Xcel Energy has paid quarterly dividends to its shareholders. For the first quarter of 2004, Xcel Energy paid dividends to its shareholders of $0.1875 per share. In each of the last three quarters of 2004, Xcel Energy paid dividends to its shareholders of $0.2075. For each of the four quarters of 2003, Xcel Energy paid dividends to its shareholders of $0.1875 per share. For each of the first two quarters of 2002, Xcel Energy paid dividends to its shareholders of $0.375 per share. In each of the third and fourth quarters of 2002, Xcel Energy paid dividends to its shareholders of $0.1875 per share. Dividends on common stock are paid as declared by the board of directors.

Dividend and Other Capital-Related Restrictions Under the PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may declare and pay dividends only out of retained earnings. In May 2003, Xcel Energy received authorization from the SEC to pay an aggregate amount of $152 million of common and preferred dividends out of capital and unearned surplus. Xcel Energy used this authorization to declare and pay approximately $150 million for its first and second quarter dividends in 2003. At Dec. 31, 2004, Xcel Energy's retained earnings were approximately $396.6 million.

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, 2004, was 81 percent. 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 $833 million in additional cash dividends on common stock at Dec. 31, 2004.

Registered holding companies and certain of their subsidiaries, including Xcel Energy and its utility subsidiaries, are limited, under PUHCA, in their ability to issue securities. Such registered holding companies and their subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC. Because Xcel Energy does not qualify for any of the main exemptive rules, it sought and received financing authority from the SEC under PUHCA for various financing arrangements. Xcel Energy's current financing authority permits it, subject to satisfaction of certain conditions, to issue through June 30, 2005, up to $2.5 billion of common stock and long-term debt and $1.5 billion of short-term debt at the holding company level. Xcel Energy has $2.2 billion of long-term debt outstanding and common stock at the holding company level, including the $600 million multi-year credit facility that was entered into during November 2004.

On Dec. 17, 2004, Xcel Energy filed an application with the SEC requesting additional financing authorization beyond June 30, 2005. If approved, the new financing authority would extend through June 30, 2008. The new application requests the authority for Xcel Energy to issue up to $1.8 billion of new long-term debt, common equity and equity-linked securities and $1.0 billion of short-term debt securities during the new authorization period, provided that the aggregate amount of long-term debt, common equity, equity-linked and short-term debt securities issued during the new authorization period does not exceed $2.0 billion. Xcel Energy expects the SEC to issue an order prior to the expiration of the existing authorization.

Xcel Energy's ability to issue securities under the financing authority is subject to a number of conditions. One of the conditions of the financing authority is that Xcel Energy's ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. As of Dec. 31, 2004, such common equity ratio was approximately 42 percent. Additional conditions require that a security to be issued that is rated, be rated investment grade by at least one nationally recognized rating agency. Finally, all outstanding securities that are rated must be rated investment grade by at least one nationally recognized rating agency. As of Dec. 31, 2004, Xcel Energy's senior unsecured debt was considered investment grade by at least one nationally recognized rating agency.

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

12. BENEFIT PLANS AND OTHER POSTRETIREMENT BENEFITS

Xcel Energy offers various benefit plans to its benefit employees. Approximately 51 percent of benefiting employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2004, NSP-Minnesota had 2,197 and NSP-Wisconsin had 414 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2007. PSCo had 2,177 bargaining employees covered under a collective-bargaining agreement, which expires in May 2006. SPS had 739 bargaining employees covered under a collective-bargaining agreement, which expires in October 2005.

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. In 2004, Xcel Energy completed a review of its pension plan asset allocation and adopted revised asset allocation targets. The target range for our pension asset allocation is 60 percent in equity investments, 20 percent in fixed income investments, no cash investments and 20 percent in nontraditional investments, such as real estate, timber ventures, private equity and a diversified commodities index.

The actual composition of pension plan assets at Dec. 31 was:

	2004	*2003*
Equity securities	**69%**	75%
Debt securities	**19**	14
Real estate	**4**	3
Cash	**1**	–
Nontraditional investments	**7**	8
	100%	100%

During 2003, Xcel Energy entered into a number of hedging arrangements within the pension trust designed to provide protection from a loss of asset value in the event of a broad decline in equity prices. These arrangements were closed out in December 2004.

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 12.8 percent, which is greater than the current assumption level. The pension cost determinations assume 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 that can provide a higher-than-average return. As is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels actually achieved by pension assets in any year. Investment returns in 2002 were below the assumed level of 9.5 percent, but in 2003 investment returns exceeded the assumed level of 9.25 percent, and in 2004 investment returns exceeded the assumed level of 9.0 percent. Xcel Energy continually reviews its pension assumptions. In 2005, Xcel Energy changed the investment-return assumption to 8.75 percent to reflect general return expectations for various asset classes in the marketplace.

Benefit Obligations A comparison of the actuarially computed pension-benefit obligation and plan assets, on a combined basis, is presented in the following table:

(Thousands of dollars)	*2004*	*2003*
Accumulated Benefit Obligation at Dec. 31	**$2,575,317**	$2,512,138
Change in Projected Benefit Obligation		
Obligation at Jan. 1	**$2,632,491**	$2,505,576
Service cost	**58,150**	67,449
Interest cost	**165,361**	170,731
Plan amendments	**–**	85,937
Actuarial loss	**133,552**	82,197
Settlements	**(27,627)**	(9,546)
Curtailment gain	**–**	(26,407)
Benefit payments	**(229,664)**	(243,446)
Obligation at Dec. 31	**$2,732,263**	$2,632,491
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$3,024,661**	$2,639,963
Actual return on plan assets	**284,600**	605,978
Employer contributions	**10,046**	31,712
Settlements	**(27,627)**	(9,546)
Benefit payments	**(229,664)**	(243,446)
Fair value of plan assets at Dec. 31	**$3,062,016**	$3,024,661
Funded Status of Plans at Dec. 31		
Net asset	**$ 329,753**	$ 392,170
Unrecognized transition asset	**–**	(7)
Unrecognized prior service cost	**244,437**	273,725
Unrecognized loss	**176,957**	9,710
Net pension amounts recognized on Consolidated Balance Sheets	**$ 751,147**	$ 675,598
Prepaid pension asset recorded *(a)*	**$ 642,873**	$ 566,568
Intangible asset recorded – prior service costs	**4,594**	5,724
Minimum pension liability recorded	**(62,669)**	(54,647)
Accumulated other comprehensive income recorded – pretax	**170,554**	158,083
Accumulated other comprehensive income recorded – net of tax	**106,007**	98,072
Measurement Date	Dec. 31, 2004	Dec. 31, 2003
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	**6.00%**	6.25%
Expected average long-term increase in compensation level	**3.50%**	3.50%

(a) $18.5 million of the 2004 prepaid pension asset and $18.7 million of the 2003 prepaid pension asset relates to Xcel Energy's remaining obligation for companies that are now classified as discontinued operations.

During 2002, one of Xcel Energy's pension plans became underfunded, and at Dec. 31, 2004, had projected benefit obligations of $694.4 million, which exceeded plan assets of $590.1 million. All other Xcel Energy plans in the aggregate had plan assets of $2.5 billion and projected benefit obligations of $2.0 billion on Dec. 31, 2004. A minimum pension liability of $62.7 million was recorded related to the underfunded plan as of that date. A corresponding reduction in Accumulated Other Comprehensive Income, a component of Stockholders' Equity, also was recorded, as previously recorded prepaid pension assets were reduced to record the minimum liability. Net of the related deferred income tax effects of the adjustments, total Stockholders' Equity was reduced by $106.0 million at Dec. 31, 2004, due to the minimum pension liability for the underfunded plan.

Cash Flows Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in the years 2002 through 2004 for Xcel Energy's pension plans, and is not expected to require cash funding in 2005. PSCo elected to make voluntary contributions to its pension plan for bargaining employees of $30 million in 2003 and $9 million in 2004, and Cheyenne voluntarily contributed $1 million to its pension plan for bargaining employees in 2004.

Benefit Costs The components of net periodic pension cost (credit) are:

(Thousands of dollars)	***2004***	*2003*	*2002*
Service cost	**$ 58,150**	$ 67,449	$ 65,649
Interest cost	**165,361**	170,731	172,377
Expected return on plan assets	**(302,958)**	(322,011)	(339,932)
Curtailment (gain) loss	**–**	(17,363)	–
Settlement (gain) loss	**(926)**	(1,135)	–
Amortization of transition asset	**(7)**	(1,996)	(7,314)
Amortization of prior service cost	**30,009**	28,230	22,663
Amortization of net gain	**(15,207)**	(44,825)	(69,264)
Net periodic pension cost (credit) under SFAS No. 87 *(a)*	**(65,578)**	(120,920)	(155,821)
Credits not recognized due to effects of regulation	**38,967**	51,311	71,928
Net benefit cost (credit) recognized for financial reporting	**$(26,611)**	$(69,609)	$(83,893)
Significant Assumptions Used to Measure Costs			
Discount rate	**6.25%**	6.75%	7.25%
Expected average long-term increase in compensation level	**3.50%**	4.00%	4.50%
Expected average long-term rate of return on assets	**9.00%**	9.25%	9.50%

(a) Includes pension credits related to discontinued operations of $4.7 million for 2004, $18.3 million for 2003 and $10.1 million for 2002. The 2003 credit is largely due to a $20.0 million curtailment gain related to termination of NRG employees as a result of the divestiture of NRG in December 2003.

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 2005 pension cost calculations will be 8.75 percent. The cost calculation uses a market-related valuation of pension assets, which reduces year-to-year volatility by recognizing the differences between assumed and actual investment returns over a five-year period.

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 $21.9 million in 2004, $15.9 million in 2003 and $18.3 million in 2002.

Until May 6, 2002, Xcel Energy had a leveraged employee stock ownership plan (ESOP) that covered substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy made contributions to this noncontributory, defined contribution plan to the extent it realized tax savings from dividends paid on certain ESOP shares. ESOP contributions had no material effect on Xcel Energy earnings because the contributions were essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocated leveraged ESOP shares to participants when it repaid ESOP loans with dividends on stock held by the ESOP.

In May 2002, the ESOP was terminated and its assets were combined into the Xcel Energy retirement savings 401(k) plan. The ESOP component of the 401(k) plan is no longer leveraged.

Xcel Energy's leveraged ESOP held 10.7 million shares of Xcel Energy common stock at May 6, 2002. Xcel Energy excluded an average of 0.7 million uncommitted leveraged ESOP shares from 2002 earnings-per-share calculations. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and were used by Xcel Energy for the 2002 employer matching contribution to its 401(k) plan.

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 the former 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 the former 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. PSCo transitioned to full accrual accounting for SFAS No. 106 costs between 1993 and 1997, consistent with the accounting requirements for rate-regulated enterprises. The Colorado jurisdictional SFAS No. 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS No. 106 costs, with regulatory differences fully amortized prior to 1997.

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. In 2004, the investment strategy for the union asset fund was changed to increase the exposure to equity funds. 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:

	2004	*2003*
Fixed income/debt securities	**21%**	2%
Equity and equity mutual fund securities	**54**	14
Cash equivalents	**25**	84
	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. Given the fairly short time period in which funding has been required, Xcel Energy does not consider the actual historical returns achieved by its postretirement health care fund asset portfolio to be significant in establishing long-term return assumptions. Instead, Xcel Energy considers the long-term return levels projected and recommended by investment experts, weighted for the target mix of asset categories in our 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:

(Thousands of dollars)	*2004*	*2003*
Change in Benefit Obligation		
Obligation at Jan. 1	**$775,230**	$767,975
Service cost	**6,100**	5,893
Interest cost	**52,604**	52,426
Acquisitions (divestitures)	**–**	(31,584)
Plan amendments	**(1,600)**	(33,304)
Plan participants' contributions	**9,532**	16,577
Actuarial loss	**148,341**	122,864
Curtailments	**–**	(249)
Benefit payments	**(61,082)**	(60,754)
Impact of Medicare Prescription Drug, Improvement and Modernization Act of 2003	**–**	(64,614)
Obligation at Dec. 31	**$929,125**	$775,230
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	**$285,861**	$250,983
Actual return on plan assets	**21,950**	11,045
Plan participants' contributions	**9,532**	16,577
Employer contributions	**62,406**	68,010
Benefit payments	**(61,082)**	(60,754)
Fair value of plan assets at Dec. 31	**$318,667**	$285,861
Funded Status at Dec. 31		
Net obligation	**$610,458**	$489,369
Unrecognized transition asset (obligation)	**(117,600)**	(133,778)
Unrecognized prior service cost	**17,914**	20,093
Unrecognized gain (loss)	**(383,026)**	(255,174)
Accrued benefit liability recorded *(a)*	**$127,746**	$120,510
Measurement Date	**Dec. 31, 2004**	Dec. 31, 2003
Significant Assumptions Used to Measure Benefit Obligations		
Discount rate for year-end valuation	**6.00%**	6.25%

(a) $0.7 million of the 2004 accrued benefit liability and $1.1 million of the 2003 accrued benefit liability relate to Xcel Energy's remaining obligation for companies that are now classified as discontinued operations.

Effective Dec. 31, 2004, Xcel Energy raised its initial medical trend assumption from 6.5 percent to 9.0 percent and lowered the ultimate trend assumption from 5.5 percent to 5.0 percent. The period until the ultimate rate is reached also was increased from two years to six years. This trend assumption was used to value the actuarial benefit obligations at year-end 2004, and will be used in 2005 retiree medical cost determinations. 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, 2004	$107,208
1-percent decrease in APBO components at Dec. 31, 2004	$ (88,864)
1-percent increase in service and interest components of the net periodic cost	$ 8,052
1-percent decrease in service and interest components of the net periodic cost	$ (6,543)

The employer subsidy for retiree medical coverage was eliminated for former New Century Energies, Inc. nonbargaining employees who retire after July 1, 2003.

Xcel Energy's subsidiary, Viking, was sold on Jan. 17, 2003. The sale created a one-time curtailment gain of $0.8 million. NRG participants withdrew from the retiree life plan, resulting in a $1.3 million one-time curtailment gain in 2003.

NRG employees' participation in the Xcel Energy postretirement health care plan ended when NRG emerged from bankruptcy on Dec. 5, 2003. A settlement gain of $0.9 million was recognized.

Cash Flows The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy expects to contribute approximately $73 million during 2005.

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

(Thousands of dollars)	***2004***	*2003*	*2002*
Service cost	**$ 6,100**	$ 5,893	$ 7,173
Interest cost	**52,604**	52,426	50,135
Expected return on plan assets	**(23,066)**	(22,185)	(21,030)
Curtailment (gain) loss	**–**	(2,128)	–
Settlement (gain) loss	**–**	(916)	–
Amortization of transition obligation	**14,578**	15,426	16,771
Amortization of prior service cost (credit)	**(2,179)**	(1,533)	(1,130)
Amortization of net loss (gain)	**21,651**	15,409	5,380
Net periodic postretirement benefit cost (credit) under SFAS No. 106 *(a)*	**69,688**	62,392	57,299
Additional cost recognized due to effects of regulation	**3,891**	3,883	4,043
Net cost recognized for financial reporting	**$73,579**	$66,275	$61,342
Significant assumptions used to measure costs (income)			
Discount rate	**6.25%**	6.75%	7.25%
Expected average long-term rate of return on assets (pretax)	**5.50%–8.50%**	8.00%–9.00%	9.00%

(a) Includes amounts related to discontinued operations of $1.3 million of cost in 2004, $(1.9) million of cost in 2003 and $3.6 million of cost in 2002.

Impact of 2003 Medicare Legislation On Dec. 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. This new coverage is generally effective Jan. 1, 2006. Many of Xcel Energy's retiree medical programs provide prescription drug coverage for retirees over age 65 with coverage at least equivalent to the benefit to be provided under Medicare. While retirees remain in Xcel Energy's postretirement health care plan without participating in the new Medicare prescription drug coverage, Medicare will share the cost of Xcel Energy's plan. This legislation has therefore reduced Xcel Energy's share of the obligation for future retiree medical benefits.

As of Dec. 31, 2003, Xcel Energy had reduced the postretirement health care benefit obligation by $64.6 million due to the expected sharing of the cost of the program by Medicare under the new legislation. Also, beginning in 2004, the annual net periodic postretirement benefit cost was reduced by approximately $10 million as a result of the expected sharing of the cost of the program by Medicare, with similar savings expected in subsequent years. These estimated reductions do not reflect any changes that may result in future levels of participation in the plan or the associated per-capita claims cost due to the availability of prescription drug coverage for Medicare-eligible retirees. Also, in reflecting this legislation, Medicare cost sharing for a plan has been assumed only if Xcel Energy's projected contribution to the plan is expected to be at least equal to the Medicare Part D basic benefit.

Projected Benefit Payments

The following table lists Xcel Energy's projected benefit payments for the pension and postretirement benefit plans:

(Thousands of dollars)	*Projected Pension Benefit Payments*	*Gross Projected Postretirement Health Care Benefit Payments*	*Expected Medicare Part D Subsidies*	*Net Projected Postretirement Health Care Benefit Payments*
2005	$ 199,117	$ 59,642	$ –	$ 59,642
2006	$ 211,830	$ 61,652	$ 4,297	$ 57,355
2007	$ 217,582	$ 63,640	$ 4,591	$ 59,049
2008	$ 225,050	$ 65,393	$ 4,821	$ 60,572
2009	$ 231,704	$ 67,036	$ 5,008	$ 62,028
2010–2014	$1,202,161	$352,308	$27,192	$325,116

13. DETAIL OF INTEREST AND OTHER INCOME, NET OF NONOPERATING EXPENSES

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

(Thousands of dollars)	***2004***	*2003*	*2002*
Interest income	**$22,688**	$16,306	$29,237
Equity income in unconsolidated affiliates	**7,956**	5,628	1,835
Gain on disposal of assets	**4,725**	9,365	10,076
Other nonoperating income	**4,048**	3,160	14,170
Interest expense on corporate-owned life insurance and other employee-related insurance policies	**(24,601)**	(21,320)	(18,053)
Other nonoperating expense	**(8)**	(3,038)	(462)
Total interest and other income, net of nonoperating expenses	**$14,808**	$10,101	$36,803

14. 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 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 our operations. The use of these derivative instruments is discussed in further detail below.

Utility Commodity Price Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation and retail distribution operations. Commodity price risk is managed by entering into both long- and short-term physical purchase and sales contracts for electric power, natural gas, coal and fuel oil. Commodity risk also is managed through the use of financial derivative instruments. Xcel Energy and its utility subsidiaries utilize these derivative instruments to reduce the volatility in the cost of commodities acquired on behalf of our retail customers even though regulatory jurisdiction may provide for a dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments is done consistently with the local jurisdictional cost-recovery mechanism. Xcel Energy's risk-management policy allows it to manage market price risk within each rate-regulated operation to the extent such exposure exists.

Short-Term Wholesale and Commodity Trading Risk Xcel Energy's subsidiaries conduct various marketing and commodity trading activities, including the purchase and sale of electric capacity and energy and other energy-related instruments. These activities are primarily focused on specific regions where market knowledge and experience have been obtained and are generally less than one year in length. Xcel Energy's risk-management policy allows management to conduct the marketing activity within approved guidelines and limitations as approved by our risk-management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

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

Foreign Currency Exchange Risk Due to the discontinuance of NRG and Xcel Energy International's operations in 2003, as discussed in Notes 3 and 4 to the Consolidated Financial Statements, Xcel Energy no longer has material foreign currency exchange risk.

Types of and Accounting for Derivative Instruments

Xcel Energy uses a number of different derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not qualifying for the normal purchases and normal sales exception, as defined by SFAS No. 133, as amended, are recorded at fair value. The classification of the fair value for these derivative instruments is dependent on the designation of a qualifying hedging relationship. The fair value of derivative instruments not designated in a qualifying hedging relationship is reflected in current earnings. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The designation of a cash flow hedge permits the classification of fair value to be recorded within Other Comprehensive Income, to the extent effective. The designation of a fair value hedge permits a derivative instrument's gains or losses to offset the related results of the hedged item in the Consolidated Statements of Operations, to the extent effective.

SFAS No. 133, as amended, 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 hedging relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk-management objectives and strategies for undertaking the hedged transaction. Xcel Energy and its subsidiaries also formally assess, both at inception and on an ongoing basis, if required, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

Hedge effectiveness is recorded based on the nature of the item being hedged. Hedging transactions for the sales of electric energy are recorded as a component of revenue; hedging transactions for fuel used in energy generation are recorded as a component of fuel costs; hedging transactions for natural gas purchased for resale are recorded as a component of natural gas costs; and hedging transactions for interest-rate swaps and lock agreements are recorded as a component of interest expense. Certain Xcel Energy utility subsidiaries are allowed to recover in electric or natural gas rates the costs of certain financial instruments acquired to reduce commodity cost volatility.

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

The effective portion of the change in the fair value of a derivative instrument qualifying as a cash flow hedge is recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument's change in fair value is recognized in current earnings.

Commodity Cash Flow Hedges Xcel Energy and its subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At Dec. 31, 2004, Xcel Energy had various commodity-related contracts classified as cash flow hedges extending through 2009. Amounts deferred from current earnings are recorded in earnings as the hedged purchase or sales transaction is settled. This could include the purchase or sale of energy and energy-related products, the use of natural gas to generate electric energy or natural gas purchased for resale.

As of Dec. 31, 2004, Xcel Energy had no amounts accumulated in Other Comprehensive Income that are expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Xcel Energy had no ineffectiveness related to commodity cash flow hedges during the years ended Dec. 31, 2004 and 2003.

Interest Rate Cash Flow Hedges Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively fix the interest payments on certain floating-rate debt obligations. These derivative instruments are designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2004, Xcel Energy had net losses related to interest rate swaps of approximately $1.1 million accumulated in Other Comprehensive Income that it expects to recognize in earnings during the next 12 months.

Xcel Energy and its subsidiaries also enter into interest rate lock agreements, including treasury-rate locks and forward starting swaps, that effectively fix the yield or price on a specified treasury security for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

As of Dec. 31, 2004, Xcel Energy had net gains related to settled interest rate lock agreements of approximately $1.4 million accumulated in Other Comprehensive Income that it expects to recognize in earnings during the next 12 months.

Xcel Energy had no ineffectiveness related to interest rate cash flow hedges during the years ended Dec. 31, 2004 and 2003.

Financial Impact of Qualifying Cash Flow Hedges The impact of qualifying cash flow hedges on Xcel Energy's Other Comprehensive Income, included in the Consolidated Statements of Stockholders' Equity, are detailed in the following table:

(Millions of dollars)	
Accumulated other comprehensive income related to hedges at Dec. 31, 2001	$34.2
After-tax net unrealized losses related to derivatives accounted for as hedges	(68.3)
After-tax net realized losses on derivative transactions reclassified into earnings	28.8
Acquisition of NRG minority interest	27.4
Accumulated other comprehensive income related to hedges at Dec. 31, 2002	$22.1
After-tax net unrealized gains related to derivatives accounted for as hedges	24.1
After-tax net realized gains on derivative transactions reclassified into earnings	(38.1)
Accumulated other comprehensive income related to hedges at Dec. 31, 2003	$ 8.1
After-tax net unrealized gains related to derivatives accounted for as hedges	1.6
After-tax net realized gains on derivative transactions reclassified into earnings	(9.6)
Accumulated other comprehensive income related to hedges at Dec. 31, 2004	**$ 0.1**

Fair Value Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge is offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the gains or losses of the derivative instrument to offset, in the same period, the gains and losses of the hedged item. The ineffective portion of a derivative instrument's change in fair value is recognized in current earnings.

Interest Rate Fair Value Hedges Xcel Energy enters into interest rate swap instruments that effectively hedge the fair value of fixed-rate debt. The fair market value of Xcel Energy's interest rate swaps at Dec. 31, 2004, was a liability of approximately $8.3 million.

Hedges of Foreign Currency Exposure of a Net Investment in Foreign Operations

Due to the discontinuance of NRG and Xcel Energy International's operations in 2003, as discussed in Notes 3 and 4 to the Consolidated Financial Statements, Xcel Energy no longer has material foreign currency exposure.

Normal Purchases or Normal Sales Contracts

Xcel Energy's utility subsidiaries enter into contracts for the purchase and sale of various commodities for use in their business operations. SFAS No. 133, as amended, requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133, as amended, as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In addition, normal purchases and normal sales contracts must have a price based on an underlying that is clearly and closely related to the asset being purchased or sold. An underlying is 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.

Contracts that meet the requirements of normal are documented and exempted from the accounting and reporting requirements of SFAS No. 133, as amended. In June 2003, the Derivatives Implementation Group of the FASB issued Implementation Issue No. C20 (C20) to clarify the terms clearly and closely related to normal purchases and sales contracts, as included in SFAS No. 133, as amended. Xcel Energy's implementation of C20 in 2003 had no impact on earnings. However, certain contracts did require a one-time fair value adjustment as of Oct. 1, 2003. The result of this adjustment was the creation of a derivative liability with an offsetting regulatory asset to reflect expected recovery of the amounts from customers. The derivative liability and related regulatory asset will be amortized over the respective lives of the contracts. See Note 18 to the Consolidated Financial Statements.

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

Normal purchases and normal sales contracts are accounted for as executory contracts as required under GAAP.

The following discussion briefly describes the use of derivative commodity and financial instruments at Xcel Energy and its subsidiaries, and discloses the respective fair values at Dec. 31, 2004 and 2003.

Commodity Trading Instruments At Dec. 31, 2004 and 2003, the fair value of commodity trading contracts was $0.0 million and $4.2 million, respectively.

Regulated Commodity Instruments The fair value of qualifying cash flow hedges is presented as a component of Other Comprehensive Income in the Consolidated Statements of Stockholders' Equity. At Dec. 31, 2004 and 2003, the fair value of these contracts was $(24.6) million and $(11.2) million, respectively.

Nonregulated Commodity Instruments Xcel Energy's nonregulated operations use a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2004 and 2003, the fair value of these contracts was $0.0 million and $1.5 million, respectively.

The fair value of cash flow hedges related to nonregulated operations for 2003 is included in discontinued operations.

Financial Instruments Xcel Energy and its subsidiaries had interest rate swaps outstanding with a fair value that was a liability of approximately $30 million at Dec. 31, 2004. On Dec. 31, 2003, subsidiaries of Xcel Energy had interest rate swaps outstanding with a fair value that was a liability of approximately $18 million.

15. FINANCIAL INSTRUMENTS

The estimated Dec. 31 fair values of Xcel Energy's financial instruments, separately identifying amounts that are within continuing operations and within discontinued operations, are as follows:

	2004		2003	
(Thousands of dollars)	*Carrying Amount*	*Fair Value*	*Carrying Amount*	*Fair Value*
Continuing Operations				
Long-term investments	**$ 961,583**	**$ 961,473**	$ 828,802	$ 827,375
Long-term debt, including current portion	**$6,716,675**	**$7,391,616**	$6,653,808	$7,337,597
Discontinued Operations				
Long-term debt, including current portion	**$ 24,800**	**$ 26,333**	$ 25,000	$ 25,860

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 because of the short-term nature of these instruments or because the stated rates approximate market rates. The fair values of Xcel Energy's long-term investments, mainly debt securities in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair 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, 2004 and 2003. 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.

Xcel Energy provides guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantee. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral. On Dec. 31, 2004, Xcel Energy had the following amount of guarantees and exposure under these guarantees, including those related to e prime Energy Marketing, Inc., e prime Florida, Inc., Cheyenne and Seren, which are components of discontinued operations:

(Millions of dollars) *Nature of Guarantee*	*Guarantor*	*Guarantee Amount*	*Current Exposure*	*Term or Expiration Date*	*Triggering Event Requiring Performance*	*Assets Held as Collateral*
Guarantee performance and payment of surety bonds for itself and its subsidiaries *(c) (g)*	Xcel Energy	$109.0	$7.4	2005–2008, 2012, 2014, 2015 and 2022	*(d)*	N/A
Guarantee performance and payment of surety bonds for those subsidiaries	Various subsidiaries *(g)*	$292.9	$ –	2005, 2006 and 2008	*(d)*	N/A
Two guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements *(h)*	Xcel Energy	$ 26.5	$ –	2011 and 2013	*(a)*	N/A
Guarantee the indemnification obligations of Xcel Energy Markets Holdings Inc. under a purchase agreement with Border Viking Co.	Xcel Energy	$ 30.7	$ –	Continuing	*(b)*	N/A
Guarantees for e prime Energy Marketing Inc. and e prime Florida Inc.'s guaranteeing payments of energy, capacity and financial transactions	Xcel Energy	$ 5.0	$0.3	2005	*(a)*	N/A
Guarantee of customer loans to encourage business growth and expansion	NSP-Wisconsin	$ 0.4	$0.4	Latest expiration in 2006	*(e)*	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$ 0.4	$0.4	Latest expiration in 2007	*(a)*	*(f)*
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$ 4.8	$ –	Continuing	*(a)*	N/A

(a) Nonperformance and/or nonpayment.

(b) Losses caused by default in performance of covenants or breach of any warranty or representation in the purchase agreement.

(c) Includes one performance bond with a notional amount of $11.1 million that guarantee the performance of Planergy Housing Inc., a subsidiary of Xcel Energy that was sold to Ameresco Inc. on Dec. 12, 2003. Ameresco Inc. has agreed to indemnify Xcel Energy for any liability arising out of any surety bond.

(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) Non-timely payment of the obligations or at the time the debtor becomes the subject of bankruptcy or other insolvency proceedings.

(f) Security interest in underlying receivable agreements.

(g) 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.

(h) The guarantees associated with Cheyenne were terminated upon consummation of the sale on Jan. 21, 2005.

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, 2004, there was $82.2 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.

16. COMMITMENTS AND CONTINGENCIES

Commitments

Legislative Resource Commitments In 1994 and 2003, NSP-Minnesota received Minnesota legislative approval for additional on-site temporary spent-fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Commitments related to the 17 dry cask storage containers approved in 1994 have been fulfilled. The use of 29 dry cask storage containers has been approved. As of Dec. 31, 2004, NSP-Minnesota had loaded 17 of the containers.

On May 29, 2003, the Minnesota Legislature enacted legislation that will enable NSP-Minnesota to store at least 12 more casks of spent fuel outside the Prairie Island nuclear generating plant, in addition to those approved in 1994. This will allow NSP-Minnesota to continue to operate the plant and store spent fuel in the facility until its licenses with the Nuclear Regulatory Commission (NRC) expire in 2013 and 2014. The legislation transfers the primary authority concerning future spent-fuel storage issues from the state Legislature to the MPUC. It also allows for additional storage without the requirement of an affirmative vote from the state Legislature, if the NRC extends the licenses of the Prairie Island and Monticello plants and the MPUC grants a certificate of need for such additional storage. The legislation requires NSP-Minnesota to add at least 300 megawatts of additional wind power by 2010 with an option to own 100 megawatts of this power.

The legislation also requires payments during the remaining operating life of the Prairie Island plant. These payments include: $2.25 million per year to the Prairie Island Tribal Community beginning in 2004; 5 percent of NSP-Minnesota's conservation program expenditures (estimated at $2 million per year) to the University of Minnesota for renewable energy research; and an increase in funding commitments to the previously established Renewable Development Fund from $8.5 million in 2002 to $16 million per year beginning in 2003. The legislation also designated $10 million in one-time grants to the University of Minnesota for additional renewable energy research, which is to be funded from commitments already made to the Renewable Development Fund. All of the cost increases to NSP-Minnesota from these required payments and funding commitments are expected to be recoverable in Minnesota retail customer rates, mainly through existing cost-recovery mechanisms. Funding commitments to the Renewable Development Fund would terminate after the Prairie Island plant discontinues operation unless the MPUC determines that NSP-Minnesota failed to make a good faith effort to store or dispose of the spent fuel out of state, in which case NSP-Minnesota would have to make payments in the amount of $7.5 million per year.

Capital Commitments As discussed in Liquidity and Capital Resources under Management's Discussion and Analysis, the estimated cost, as of Dec. 31, 2004, of the capital expenditure programs and other capital requirements of Xcel Energy and its subsidiaries is approximately $1.5 billion in 2005, $2.3 billion in 2006 and $1.8 billion in 2007.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, 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 requirements to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies may impact actual capital requirements.

Leases Xcel Energy and its subsidiaries lease a variety of equipment and facilities used in the normal course of business. Some of these leases qualify as capital leases and are accounted for accordingly. The capital leases contractually expire in 2025 and 2029. The net book value of property under capital leases was approximately $48.9 million and $47.7 million at Dec. 31, 2004 and 2003, respectively. Assets acquired under capital leases are recorded as property at the lower of fair market value or the present value of future lease payments, and are amortized over their actual contract term in accordance with practices allowed by regulators. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

The remainder of the leases, primarily real estate leases and leases of coal-hauling railcars, trucks, cars and power-operated equipment are accounted for as operating leases. Rental expense under operating lease obligations for continuing operations was approximately $57.5 million, $65.0 million and $67.8 million for 2004, 2003 and 2002, respectively.

Expected operating lease expenses and future commitments under capital leases for continuing operations are:

(Millions of dollars)	*Operating Leases*	*Capital Leases*
2005	$55	$ 7
2006	$59	$ 6
2007	$59	$ 6
2008	$57	$ 6
2009	$58	$ 6
Thereafter	$72	$ 74
Total minimum obligation		$105
Interest		(56)
Present value of minimum obligation		$ 49

Technology Agreement Xcel Energy has a contract that extends through 2011 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at our option, although there are financial penalties for early termination. In 2004, Xcel Energy paid IBM $152.5 million under the contract and $24.5 million for other project business. The contract also has a committed minimum payment each year from 2005 through 2011.

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 2005 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.2 billion of coal, $133.1 million of nuclear fuel and $2.8 billion of natural gas, including $1.0 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 adjustment mechanisms of the ratemaking process, which provide for pass-through of most fuel costs to customers.

Purchased Power Agreements The utility subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2033. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on actual power taken under the contracts. Certain contractual payment obligations are adjusted based on indexes. However, the effects of price adjustments are mitigated through cost-of-energy adjustment mechanisms.

At Dec. 31, 2004, the estimated future payments for capacity that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Thousands of dollars)	
2005	$ 554,786
2006	588,335
2007	605,154
2008	600,309
2009	572,006
2010 and thereafter	3,584,923
Total	$6,505,513

Environmental Contingencies

Xcel Energy is subject to regulations covering air and water quality, land use, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. Compliance is continually assessed. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating facilities.

Site Remediation Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2004, there were three categories of sites:
- the site of a former federal uranium enrichment facility;
- sites of former manufactured gas plants (MGPs) operated by our subsidiaries or predecessors; and
- third-party sites, such as landfills, to which Xcel Energy is alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes.

Xcel Energy records a liability when enough information is obtained to develop an estimate of the cost of environmental remediation and revises the estimate as information is received. The estimated remediation cost may vary materially.

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

Estimates are revised as facts become known. At Dec. 31, 2004, the liability for the cost of remediating these sites was estimated to be $44.0 million, of which $19.3 million was considered to be a current liability. Some of the cost of remediation may be recovered from:
- insurance coverage;
- other parties that have contributed to the contamination; and
- customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. Estimates have been recorded for Xcel Energy's future costs for these sites.

Federal Uranium Enrichment Facility

Approximately $5.4 million of the long-term liability and $4.6 million of the current liability relate to a DOE assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. These environmental liabilities do not include accruals recorded and collected from customers in rates for future nuclear fuel disposal costs or decommissioning costs related to NSP-Minnesota's nuclear generating plants. See Note 17 to the Consolidated Financial Statements for further discussion of nuclear obligations.

Manufactured Gas Plant Sites

Levee Station Manufactured Gas Plant Site A portion of NSP-Minnesota's High Bridge plant coal yard is located on the site of the former Levee Station MGP site. The Levee Station was a coke-oven gas purification, storage and distribution facility. The Levee Station supplied manufactured gas to the city of St. Paul from 1918 to the early 1950s. In the 1950s, the facility was demolished, and the High Bridge coal yard was extended onto the property. In the 1990s, the site was investigated and partially remediated at a cost of approximately $2.9 million. In 2006, NSP-Minnesota plans to commence construction of the High Bridge Combined Cycle Generating Plant, as part of the MERP, on the site of the Levee Station. The construction of the new plant will require the removal of buried structures and soil and groundwater remediation. Remediation activities will begin in 2005. The cost of the additional remediation is estimated to be $5.8 million, which will be accounted for as a capital expenditure of the MERP project.

Ashland MGP Site NSP-Wisconsin was named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin, which was previously an MGP facility, and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior's Chequemegon Bay adjoining the park.

As an interim action, Xcel Energy proposed, and the Wisconsin Department of Natural Resources (WDNR) approved, a coal tar removal and groundwater treatment system for one area of concern at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer under the former MGP site to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the U.S. Environmental Protection Agency (EPA) in determining which sites require further investigation. On Nov. 14, 2003, the EPA and NSP-Wisconsin signed an administrative order on consent requiring NSP-Wisconsin to complete the remedial investigation and feasibility study for the site. On Dec. 7, 2004, the EPA approved NSP-Wisconsin's proposed work plan with minor contingencies to complete the remedial investigation and feasibility study. On Feb. 1, 2005, NSP-Wisconsin submitted its revised work plan to the EPA addressing all of the contingencies raised with the previous proposal. The final approval results in specific delineation of the investigative fieldwork and scientific assessments that must be performed. The estimated cost of carrying out the work plan is $1.3 million in 2005. Resolution of Ashland remediation issues is not currently expected until 2007 or 2008. 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.

The WDNR and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin's level of responsibility, the ultimate cost of remediating the Ashland site is not determinable. On July 2, 2004, the WDNR sent NSP-Wisconsin an invoice for recovery of past costs incurred at the Ashland site between 1994 and March 2003 in the amount of $1.4 million. On Oct. 19, 2004, the WDNR, represented by the Wisconsin Department of Justice, filed a lawsuit in Wisconsin state court for reimbursement of the past costs. This lawsuit has been stayed until further action by either party. NSP-Wisconsin is reviewing the invoice to determine whether all costs charged are appropriate. All appropriate insurance carriers have been notified of the WDNR's invoice and the lawsuit and will be invited to participate in any future efforts to address the WDNR's actions. All costs paid are expected to be recoverable in rates.

NSP-Wisconsin has recorded a liability of $17.3 million for its estimate of its share of the cost of remediating the Ashland site, using information available to date and reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site based on an expectation that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed as part of the Wisconsin biennial retail rate case process for prudence. Once approved by the PSCW, deferred MGP remediation costs, less carrying costs, are historically amortized over four or six years. In addition, 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.

Fort Collins MGP Site Prior to 1926, Poudre Valley Gas Co., a predecessor of PSCo, operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the Poudre Valley Gas Co., PSCo shut down the MGP site and has sold most of the property. Recently, an oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. In early 2004, PSCo completed implementation of a work plan to further investigate the sources of contamination of the river at a cost of approximately $1.4 million. The work resulted in removal of contaminated sediments and delineation of the extent of the contamination.

On Nov. 10, 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co., under which PSCo will perform remediation and monitoring work at an estimated cost of $8.8 million. Work is currently under way, with completion of construction anticipated in June 2005 followed by ongoing operation and maintenance.

To date, PSCo has spent approximately $3.4 million on the project, including settlement costs negotiated with the city of Fort Collins in 1998 and costs incurred by the EPA. The EPA is also expected to seek recovery of its ongoing oversight costs from PSCo. PSCo has deferred the costs recorded to date as a regulatory asset and believes that they will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

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. Since the intent is to operate most of these facilities indefinitely, Xcel Energy cannot estimate the amount or timing of payments for final removal of the asbestos. 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.

Federal Clean Water Act The federal Clean Water Act addresses the environmental impacts of cooling water intakes. In July 2004, the EPA published phase II of the rule that applies to existing cooling water intakes at steam-electric power plants. The rule will require Xcel Energy to perform additional environmental studies at 12 power plants in Minnesota, Wisconsin and Colorado to determine the impact the facilities may be having on aquatic organisms vulnerable to injury. If the studies determine the plants are not meeting the new performance standards established by the phase II rule, physical and/or operational changes may be required at these plants. 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. Preliminary cost estimates range from less than $1 million at some plants to more than $10 million at others, depending on site-specific circumstances. Based on the limited information available, total capital costs to Xcel Energy are estimated at approximately $59 million. Actual costs may be significantly higher or lower depending on issues such as the resolution of outstanding third-party legal challenges to the rule.

Leyden Gas Storage Facility In February 2001, the CPUC approved PSCo's plan to abandon the Leyden natural gas storage facility (Leyden) after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. In 2003, PSCo began flooding the facility with water, as part of an overall plan to convert Leyden into a municipal water storage facility owned and operated by the city of Arvada, Colo. In August 2003, the Colorado Oil and Gas Conservation Commission (COGCC) approved the closure plan, the last formal regulatory approval necessary before conversion. Leyden is expected to close by Dec. 31, 2005, and the city of Arvada will take over the site. PSCo is obligated to monitor the site for two years after closure. As of Dec. 31, 2004, PSCo has incurred approximately $4.8 million of costs associated with engineering buffer studies, damage claims paid to landowners and other initial closure costs. PSCo has accrued an additional $1.3 million of costs expected to be incurred through 2006 to complete the decommissioning and closure of the facility. PSCo has deferred these costs as a regulatory asset and believes that these costs will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

In December 2003, a homeowners association petitioned the EPA to assess the threat of a natural gas release from the Leyden facility pursuant to Section 105(d) of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, (CERCLA) 42 U.S.C. section 9605. The EPA completed its review in October 2004 and concluded that the risk to nearby residents is relatively low. The EPA referred the matter to its Resource Conservation and Recovery Act program. On Nov. 24, 2004, the EPA sent a letter to the COGCC requesting that the COGCC contact Xcel Energy and request certain information concerning the closure. To date, no formal request has been received by PSCo.

PSCo Notice of Violation On Nov. 3, 1999, the U.S. Department of Justice filed suit against a number of electric utilities for alleged violations of the federal Clean Air Act's New Source Review (NSR) requirements. The suit is related to alleged modifications of electric generating plants located in the South and Midwest. Subsequently, the EPA also issued requests for information pursuant to the Clean Air Act to numerous electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to the EPA's initial information requests related to PSCo plants in Colorado.

On July 1, 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the NSR requirements of the Clean Air Act at the Comanche and Pawnee plants in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid-to-late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the Clean Air Act and NSR process. It believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations, or are otherwise not subject to the NSR requirements. PSCo also believes that the projects would be expressly authorized under the EPA's NSR equipment-replacement rulemaking promulgated in October 2003. On Dec. 24, 2003, the U.S. Court of Appeals for the District of Columbia Circuit stayed this rule while it considers challenges to it. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position. As required by the Clean Air Act, the EPA met with PSCo in September 2002 to discuss the NOV.

If the EPA is successful in any subsequent litigation regarding the issues set forth in the NOV or any matter arising as a result of its information requests, it could require PSCo to install additional emission-control equipment at the plants and pay civil penalties. Civil penalties are limited to not more than $25,000 to $27,500 per day for each violation, commencing from the date the violation began. The ultimate financial impact to PSCo is not determinable at this time.

NSP-Minnesota NSR Information Request On Nov. 3, 1999, the U. S. Department of Justice filed suit, related to alleged modifications of electric generating plants located in the South and Midwest, against a number of electric utilities for alleged violations of the Clean Air Act's NSR requirements. Subsequently, the EPA also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to the EPA's initial information requests related to NSP-Minnesota plants in Minnesota. On May 22, 2002, the EPA issued a follow-up information request to Xcel Energy seeking additional information regarding NSR compliance at its plants in Minnesota. Xcel Energy completed its response to the follow-up information request during the fall of 2002.

Polychlorinated Biphenyl (PCB) Storage and Disposal In August 2004, SPS received notice from the EPA contending SPS violated PCB storage and disposal regulations with respect to storage of a drained transformer and related solids. The EPA contends the fine for the alleged violation is approximately $1.2 million. SPS is contesting the fine and is in discussions with the EPA.

Nuclear Insurance NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $10.8 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $300 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $10.5 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $100.6 million for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.1 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 $6.9 million for business interruption insurance and $26.1 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

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

Bender et al. vs. Xcel Energy On July 2, 2004, five former NRG officers filed a lawsuit against Xcel Energy in the U.S. District Court for the District of Minnesota. The lawsuit alleges, among other things, that Xcel Energy violated the ERISA by refusing to make certain deferred compensation payments to the plaintiffs. The complaint also alleges interference with ERISA benefits, breach of contract related to the nonpayment of certain stock options and unjust enrichment. The complaint alleges damages of approximately $6 million. Xcel Energy believes the suit is without merit. On Jan. 19, 2005, Xcel Energy filed a motion for summary judgement. A hearing for this motion is scheduled for April 21, 2005.

Carbon Dioxide Emissions Lawsuit On July 21, 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO_2) emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. CO_2 is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or gas-fired power plants. 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 four other utility companies filed a motion to dismiss the lawsuit, contending, among other reasons, that the lawsuit should be dismissed because it is an attempt to usurp the policy-setting role of the U.S Congress and the president. The ultimate financial impact of these lawsuits, if any, is not determinable at this time.

The issue of global climate change is receiving increased attention. Debate continues in the scientific community concerning the extent to which the earth's climate is warming, the causes of climate variations that have been observed, and the ultimate impacts that might result from a changing climate. There also is considerable debate regarding public policy for the approach that the United States should follow to address the issue. The United Nations-sponsored Kyoto Protocol, which establishes greenhouse gas reduction targets for developed nations, entered into force on Feb. 16, 2005. President Bush has declared that the United States will not ratify the protocol and is opposed to legislative mandates, preferring a program based on voluntary efforts and research on new technologies. Xcel Energy is closely monitoring the issue from both scientific and policy perspectives. While it is not possible to know the eventual outcome, Xcel Energy believes the issue merits close attention and is taking actions it believes are prudent to be best positioned for a variety of possible future outcomes. Xcel Energy is participating in a voluntary carbon management program and has established goals to reduce its volume of carbon dioxide emissions by 12 million tons by 2009 and reduce carbon intensity by 7 percent by 2012. In certain jurisdictions, the evaluation process for future generating resources incorporates the risk of future carbon limits through the use of a carbon cost adder or externality costs. Xcel Energy also is involved in other projects to improve available methods for managing carbon.

Department of Labor Audit In 2001, Xcel Energy received notice from the Department of Labor (DOL) Employee Benefit Security Administration that it intended to audit the Xcel Energy pension plan. After multiple on-site meetings and interviews with Xcel Energy personnel, the DOL indicated on Sept. 18, 2003, that it is prepared to take the position that Xcel Energy, as plan sponsor and through its delegate, the Pension Trust Administration Committee, breached its fiduciary duties under the ERISA with respect to certain investments made in limited partnerships and hedge funds in 1997 and 1998. The DOL has offered to conclude the audit at this time if Xcel Energy is willing to contribute to the plan the full amount of losses from the questioned investments, or approximately $7 million. On July 19, 2004, Xcel Energy formally responded with a letter to the DOL that asserted no fiduciary violations have occurred and extended an offer to meet to discuss the matter further. If the DOL offer is put into effect, the requested contribution would affect cash flows only and not the net income of Xcel Energy.

Xcel Energy Inc. Securities Class Action Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy's common stock between Jan. 31, 2001, and July 26, 2002, was filed in the U.S. District Court for the District of Minnesota. The complaint named Xcel Energy and current and former Xcel Energy and NRG executives as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act and Rule 10(b-5) related to allegedly false and misleading disclosures concerning various issues including but not limited to "round trip" energy trades, the nature, extent and seriousness of liquidity and credit difficulties at NRG and the existence of cross-default provisions (with NRG credit agreements) in certain of Xcel Energy's credit agreements. After filing the lawsuit, several additional lawsuits were filed with similar allegations and all have been consolidated. On Jan. 14, 2005, the District Court issued an order of preliminary approval for a settlement reached by the parties. Under the terms of the settlement, the plaintiffs are to receive $80 million, with Xcel Energy's insurance carriers paying $62.5 million, and Xcel Energy paying $17.5 million. Xcel Energy's portion of the settlement payment was accrued at Dec. 31, 2004. A hearing to consider final approval of the settlement is scheduled for April 1, 2005.

Xcel Energy Inc. Shareholder Derivative Action – Edith Gottlieb vs. Xcel Energy Inc. et al.; Essmacher vs. Brunetti; McLain vs. Brunetti In August 2002, a shareholder derivative action was filed in the U.S. District Court for the District of Minnesota (Gottlieb), purportedly on behalf of Xcel Energy, against the directors and certain present and former officers, citing allegedly false and misleading disclosures concerning various issues and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with other similar securities class actions and an amended complaint was filed. A settlement in the federal derivative lawsuit was reached in December 2004 and given preliminary approval by the District Court in an order dated Jan. 14, 2005. Under the terms of the settlement, Xcel Energy agreed to adopt certain corporate governance measures and pay plaintiff's attorneys' fees and expenses in an amount not to exceed $125,000. A hearing to consider final approval of this settlement is scheduled for April 1, 2005.

Xcel Energy Employee ERISA Actions – Newcome vs. Xcel Energy Inc.; Barday vs. Xcel Energy Inc. On Sept. 23, 2002, and Oct. 9, 2002, two essentially identical actions were filed in the U.S. District Court for the District of Colorado, purportedly on behalf of classes of employee participants in Xcel Energy's and its predecessors' 401(k) or ESOP plans, from as early as Sept. 23, 1999, forward. The complaints in the actions name as defendants Xcel Energy, its directors, certain former directors and certain present and former officers. The complaints allege violations of the ERISA in the form of breach of fiduciary duty in allowing or encouraging purchase, contribution and/or retention of Xcel Energy's common stock in the plans and making misleading statements and omissions in that regard. On Jan. 14, 2005, the District Court issued an order of preliminary approval related to a settlement reached by the parties. Under the terms of the settlement, plaintiffs are to receive a payment of $8 million, which will be paid by Xcel Energy's insurance carrier. Xcel Energy also agreed, subject to the provisions of the applicable collective bargaining agreement, to undertake to amend the Xcel Energy 401(k) savings plan and its predecessor plans and the New Century Energies employees' and stock ownership plan for bargaining unit and former nonbargaining unit employees, by permitting certain diversification of Xcel Energy stock held in participants' accounts in portions of these plans. A hearing is scheduled for April 1, 2005, to consider final approval of this settlement.

SchlumbergerSema, Inc. vs. Xcel Energy Inc. (NSP-Minnesota) Under a 1996 data services agreement, SchlumbergerSema, Inc. (SLB) provides automated meter reading, distribution automation and other data services to NSP-Minnesota. In September 2002, NSP-Minnesota issued written notice that SLB committed events of default under the agreement, including SLB's nonpayment of approximately $7.4 million for distribution automation assets. In November 2002, SLB demanded arbitration and asserted various claims against NSP-Minnesota totaling approximately $24 million for alleged breach of an expansion contract and a meter purchasing contract. In the arbitration, NSP-Minnesota asserted counterclaims against SLB, including those related to SLB's failure to meet performance criteria, improper billing, failure to pay for use of NSP-Minnesota owned property and failure to pay $7.4 million for NSP-Minnesota distribution automation assets, for total claims of approximately $41 million. NSP-Minnesota also sought a declaratory judgment from the arbitrators that would terminate SLB's rights under the data services agreement. In August 2004, the U.S. Bankruptcy Court for the District of Delaware ruled that claims related to use of certain equipment are barred unless NSP-Minnesota can establish a basis for the claims in SLB's conduct subsequent to the time of the assumption of this contract by SLB. If NSP-Minnesota can establish that basis, the decision would reduce NSP-Minnesota's damage claim by approximately $5.5 million.

Texas-Ohio Energy, Inc. vs. Centerpoint Energy et al. On Nov. 19, 2003, a class action complaint filed in the U.S. District Court for the Eastern District of California by Texas-Ohio Energy, Inc., was served on Xcel Energy naming e prime as a defendant. The lawsuit, filed on behalf of a purported class of large wholesale natural gas purchasers, alleges that e prime falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California. The case has been conditionally transferred to U.S. District Judge Pro in Nevada, who is supervising western areas wholesale natural gas marketing litigation. A motion is currently pending to transfer the case back to the Eastern District of California. The case is in the early stages, there has been no discovery and Xcel Energy intends to vigorously defend against these claims.

Cornerstone Propane Partners, L.P. et al. vs. e prime inc. et al. On Feb. 2, 2004, a purported class action complaint was filed in the U.S. District Court for the Southern District of New York against e prime and three other defendants by Cornerstone Propane Partners, L.P., Robert Calle Gracey and Dominick Viola on behalf of a class who purchased or sold one or more New York Mercantile Exchange natural gas futures and/or options contracts during the period from Jan. 1, 2000, to Dec. 31, 2002. The complaint alleges that defendants manipulated the price of natural gas futures and options and/or the price of natural gas underlying those contracts in violation of the Commodities Exchange Act. In February 2004, the plaintiff requested that this action be consolidated with a similar suit involving Reliant Energy Services. In February 2004, defendants, including e prime, filed motions to dismiss. In September 2004, the U.S. District Court denied the motions to dismiss. The case is in the early stages, there has been little discovery and Xcel Energy intends to vigorously defend against these claims.

Fairhaven Power Company vs. Encana Corporation et al. On Sept. 14, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Fairhaven Power Co. and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. The case is in the early stages, there has been no discovery and Xcel Energy intends to vigorously defend against these claims.

Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. On Nov. 29, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Utility Savings and Refund Services LLP and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. The case is in the early stages, there has been no discovery and Xcel Energy intends to vigorously defend against these claims.

Abelman Art Glass vs. Ercana Corporation et al. On Dec. 13, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Abelman Art Glass and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. The case is in the early stages, there has been no discovery and Xcel Energy intends to vigorously defend against these claims.

Hill et al. vs. PSCo et al. In late October 2003, there were two wildfires in Colorado, one in Boulder County and the other in Douglas County. There was no loss of life, but there was property damage associated with these fires. Parties have asserted that trees falling into Xcel Energy distribution lines may have caused one or both fires. On Jan. 14, 2004, an action against PSCo relating to the fire in Boulder County was filed in Boulder County District Court. There are now 46 plaintiffs, including individuals and insurance companies, and three co-defendants, including PSCo. The plaintiffs assert that they are seeking in excess of $35 million in damages. Xcel Energy believes it has insurance coverage to mitigate the liability in this matter. The ultimate financial impact to PSCo is not determinable at this time.

Other Contingencies

Tax Matters PSCo's wholly owned subsidiary, PSRI, owns and manages permanent life insurance policies, known as COLI policies, on some of PSCo's employees. At various times, borrowings have been made against the cash values of these COLI policies and deductions taken on the interest expense on these borrowings. The IRS has challenged the deductibility of such interest expense deductions and has disallowed the deductions taken in tax years 1993 through 1999.

After consultation with tax counsel, Xcel Energy contends that the IRS determination is not supported by tax law. Based upon this assessment, management believes that the tax deduction of interest expense on the COLI policy loans is in full compliance with the law. Accordingly, PSRI has not recorded any provision for income tax or related interest or penalties that may be imposed by the IRS and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years.

In April 2004, Xcel Energy filed a lawsuit in U.S. District Court for the District of Minnesota against the IRS to establish its entitlement to deduct policy loan interest for tax years 1993 and 1994. In December 2004, Xcel Energy filed suit in U.S. Tax Court in Washington D.C. for tax years 1995 through 1997. Xcel Energy expects to request that the tax court stay its petition pending the decision in the District Court litigation. The litigation could require several years to reach final resolution. Although the ultimate resolution of this matter is uncertain, it could have a material adverse effect on Xcel Energy's financial position and results of operations. Defense of Xcel Energy's position may require significant cash outlays, which may or may not be recoverable in a court proceeding.

Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2004, would reduce earnings by an estimated $311 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2004, is approximately $368 million. Xcel Energy estimates its annual earnings for 2004 would be reduced by $36 million, after tax, which represents 8 cents per share, if COLI interest expense deductions were no longer available.

Accounting for Uncertain Tax Positions In late July 2004, the FASB discussed potential changes or clarifications in the criteria for recognition of tax benefits, which may result in raising the threshold for recognizing tax benefits, which have some degree of uncertainty. The FASB has not issued any proposed guidance, but an exposure draft may be released in the first quarter of 2005. Xcel Energy is unable to determine the impact or timing of any potential accounting changes required by the FASB, but such changes could have a material financial impact.

SPS Retail Fuel Cost Recovery Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor. In May 2004, SPS filed with the PUCT its periodic request for fuel and purchased power cost recovery for electric generation and fuel management activities for the period from January 2002 through December 2003. SPS requested approval of approximately $580 million of Texas-jurisdictional fuel and purchased power costs for the two-year period. Intervenor and PUCT staff testimony was filed in October 2004 and hearings were held in December 2004. Intervenor testimony contained objections to SPS' methodology for assigning average fuel costs to wholesale sales, among other things. Recovery of $49 million to $86 million of the requested amount was contested by multiple intervenors. SPS has recorded its best estimate of any potential liability related to the impact of this proceeding. In January 2005, SPS filed its post-hearing briefs disputing the intervenor objections. Reply briefs were filed on Feb. 15, 2005, the administrative law judge is expected to issue his recommended proposal for decision by the end of April 2005, and PUCT action is expected by the end of May 2005. SPS is pursuing a settlement agreement with the parties involved.

17. NUCLEAR AND OTHER ASSET RETIREMENT OBLIGATIONS

Fuel Disposal NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately $13 million in 2004, $13 million in 2003 and $13 million in 2002. In total, NSP-Minnesota had paid approximately $335 million to the DOE through Dec. 31, 2004. However, it is not determinable whether the amount and method of the DOE's assessments to all utilities will be sufficient to fully fund the DOE's permanent storage or disposal facility.

The Nuclear Waste Policy Act 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 a dry cask facility. With the dry cask storage facility licensed by the NRC approved in 1994 and again in 2003, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least the end of its license terms in 2013 and 2014. The Monticello nuclear plant has storage capacity in the pool to continue operations until 2010. Storage availability to permit operation beyond these dates is not known at this time. All of the alternatives for spent-fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE's uranium-enrichment facilities. In 1993, NSP-Minnesota recorded the DOE's initial assessment of $46 million, which is payable in annual installments from 1993 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2004 was $4.6 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, the unamortized assessment of $12.6 million at Dec. 31, 2004, is deferred as a regulatory asset.

Regulatory Plant Decommissioning Recovery Decommissioning of NSP-Minnesota's nuclear facilities, as last approved by the MPUC, is planned for the years 2010 through 2048, assuming the prompt dismantlement method. NSP-Minnesota is currently accruing the costs for decommissioning over the MPUC approved cost-recovery period and including the accruals in Accumulated Depreciation. Upon implementation of SFAS No. 143, the decommissioning costs in Accumulated Depreciation and ongoing accruals are reclassified to a regulatory liability account. The total decommissioning cost obligation is recorded as an asset retirement obligation in accordance with SFAS No. 143.

Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are licensed to operate until 2013 and 2014, respectively. In 2003, the Minnesota Legislature changed a law that had limited expansion of on-site storage. On Aug. 25, 2004, the Xcel Energy board of directors authorized the pursuit of renewal of the operating licenses for the Monticello and Prairie Island nuclear plants. NSP-Minnesota filed its application for Monticello with the MPUC in January 2005, seeking a certificate of need for dry spent-fuel storage, and plans to file an application in early 2005 with the NRC for an operating license extension of up to 20 years. A decision regarding Monticello relicensing is expected in 2007. Plant assessments and other work for the Prairie Island applications are planned in the next two or three years. The Prairie Island license renewal process has not yet begun.

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. Funding presumes that current costs will escalate in the future at a rate of 4.19 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant-recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding. Unrealized gains on nuclear decommissioning investments are deferred as Regulatory Liabilities based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in December 2003, using 2002 cost data. An original filing was submitted to the MPUC in October 2002 and updated in August 2003; final approval was received in December 2003. The most recent cost estimate represents an annual increase in external fund accruals, along with the extension of Prairie Island cost recovery to the end of license life in 2014. The MPUC also approved the Department of Commerce recommendation to accelerate the internal fund transfer to the external funds effective July 1, 2003, ending on Dec. 31, 2005. This approval increased the fund cash contribution by approximately $29 million in 2003. Consistent with previous treatment, the transfers from the internal fund are effectively moving previously collected funds to the external fund, thereby reducing the external fund book expense. Based on the last MPUC approval requiring the acceleration of the internal fund transfer, there is a step change in the level of the overall decommissioning expense at the expiration of the transfer beginning Jan. 1, 2006. Expecting to operate Prairie Island through the end of each unit's licensed life, the approved capital recovery will allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2014. Xcel Energy believes future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2004, 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.

At Dec. 31, 2004, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $768 million. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters. These amounts are not those recorded in the financial statements for the asset retirement obligation in accordance with SFAS No. 143.

(Thousands of dollars)	***2004***
Estimated decommissioning cost obligation from most recently approved study (2002 dollars)	**$1,716,618**
Effect of escalating costs to 2004 dollars (at 4.19 percent per year)	**146,866**
Estimated decommissioning cost obligation in current dollars	**1,863,484**
Effect of escalating costs to payment date (at 4.19 percent per year)	**1,929,881**
Estimated future decommissioning costs (undiscounted)	**3,793,365**
Effect of discounting obligation (using risk-free interest rate)	**(2,139,561)**
Discounted decommissioning cost obligation	**1,653,804**
Assets held in external decommissioning trust	**918,442**
Discounted decommissioning obligation in excess of assets currently held in external trust	**$ 735,362**

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	***2004***	*2003*	*2002*
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	**$80,582**	$80,582	$51,433
Internally funded (including interest costs)	**(53,307)**	(35,906)	(18,797)
Interest cost on externally funded decommissioning obligation	**(19,026)**	(14,952)	(32)
Earnings from external trust funds	**19,026**	14,952	32
Net decommissioning accruals recorded	**$27,275**	$44,676	$32,636

Decommissioning and interest accruals are included with Regulatory Liabilities on the Consolidated Balance Sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the Consolidated Statement of Operations.

Negative accruals for internally funded portions in 2002, 2003 and 2004 reflect the impacts of the 1999 and 2002 decommissioning studies, which have approved an assumption of 100-percent external funding of future costs. Previous studies assumed a portion was funded internally; beginning in 2000, accruals are reversing the previously accrued internal portion and increasing the external portion prospectively.

Asset Retirement Obligations Xcel Energy records future plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying values of the related long-lived assets. 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 obligations has no income statement impact due to the deferral of the adjustments through the establishment of a regulatory asset pursuant to SFAS No. 71.

Asset retirement obligations have been recorded for the decommissioning of two NSP-Minnesota nuclear generating plants, the Monticello plant and the Prairie Island plant. A liability also has been recorded for the decommissioning of an NSP-Minnesota steam production plant, the Pathfinder plant. Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are licensed to operate until 2013 and 2014, respectively. Pathfinder operated as a steam production peaking facility from 1969 until its retirement.

A reconciliation of the beginning and ending aggregate carrying amounts of NSP-Minnesota's asset retirement obligations is shown in the table below for the 12 months ended Dec. 31, 2004:

(Thousands of dollars)	*Beginning Balance Jan. 1, 2004*	*Liabilities Incurred*	*Liabilities Settled*	*Accretion*	*Revisions to Prior Estimates*	***Ending Balance Dec. 31, 2004***
Steam plant retirement	$ 2,860	$ –	$ –	$ 142	$ –	**$ 3,002**
Nuclear plant decommissioning	1,021,669	–	–	66,418	–	**1,088,087**
Total liability	$1,024,529	$ –	$ –	$66,560	$ –	**$1,091,089**

The fair value of NSP-Minnesota assets legally restricted for purposes of settling the nuclear asset retirement obligations is $986 million as of Dec. 31, 2004, including external nuclear decommissioning investment funds and internally funded amounts.

Removal Costs Xcel Energy also accrues an obligation for plant removal costs for other generation, transmission and distribution facilities of its utility subsidiaries. Generally, the accrual of future non-legal 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:

(Millions of dollars)	***2004***	*2003*
NSP-Minnesota	**$323**	$324
NSP-Wisconsin	**81**	75
PSCo	**383**	351
SPS	**104**	102
Total Xcel Energy	**$891**	$852

18. REGULATORY ASSETS AND LIABILITIES

Xcel Energy's regulated businesses prepare their 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. The components of unamortized regulatory assets and liabilities of continuing operations shown on the balance sheet at Dec. 31 were:

(Thousands of dollars)	*See Note(s)*	*Remaining Amortization Period*	***2004***	*2003*
Regulatory Assets				
Net nuclear asset retirement obligations	1, 17	End of licensed life	**$ 221,864**	$ 186,989
Power purchase contract valuation adjustments	14	Term of related contract	**102,741**	154,260
AFDC recorded in plant *(a)*		Plant lives	**169,352**	153,411
Losses on reacquired debt	1	Term of related debt	**89,694**	101,176
Conservation programs *(a)*		Various	**88,253**	76,087
Nuclear decommissioning costs *(b)*		Up to three years	**20,494**	37,654
Employees' postretirement benefits other than pension	12	Three years	**31,125**	35,015
Renewable resource costs		To be determined	**38,985**	25,972
Environmental costs	16, 17	Various	**28,176**	29,195
State commission accounting adjustments *(a)*		Various	**15,945**	17,301
Plant asset recovery (Pawnee II and Metro Ash)		Two-and-a-half years	**12,258**	17,162
Unrecovered natural gas costs *(c)*	1	One to two years	**14,553**	16,008
Unrecovered electric production costs *(d)*	1	Three months	**–**	13,779
Other		Various	**17,196**	15,311
Total regulatory assets			**$ 850,636**	$ 879,320
Regulatory Liabilities				
Plant removal costs	1, 17		**$ 891,018**	$ 852,272
Pension costs – regulatory differences	12		**377,893**	338,926
Power purchase contract valuation adjustments	14		**56,874**	126,884
Unrealized gains from decommissioning investments	17		**129,028**	105,518
Investment tax credit deferrals			**92,227**	100,574
Deferred income tax adjustments	1		**69,780**	25,906
Interest on income tax refunds			**9,667**	7,233
Fuel costs, refunds and other			**4,058**	2,466
Total regulatory liabilities			**$1,630,545**	$1,559,779

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

(b) These costs do not relate to NSP-Minnesota's nuclear plants. They relate to DOE assessments, as discussed previously in Note 17, and unamortized costs for PSCo's Fort St. Vrain nuclear plant decommissioning.

(c) Excludes current portion expected to be returned to customers within 12 months of $12.4 million for 2004, and the 2003 current portion expected to be recovered from customers of $3.1 million.

(d) Excludes current portion expected to be recovered within the next 12 months of $16.1 and $55.8 million for 2004 and 2003, respectively.

19. SEGMENTS AND RELATED INFORMATION

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, New Mexico, Kansas and Oklahoma. It also makes 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.

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. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

(Thousands of dollars)	*Regulated Electric Utility*	*Regulated Natural Gas Utility*	*All Other*	*Reconciling Eliminations*	*Consolidated Total*
2004					
Operating revenues from external customers	**$6,260,938**	**$1,923,526**	**$160,795**	**$ –**	**$8,345,259**
Intersegment revenues	**1,132**	**8,735**	**38,920**	**(48,787)**	**–**
Total revenues	**$6,262,070**	**$1,932,261**	**$199,715**	**$ (48,787)**	**$8,345,259**
Depreciation and amortization	**$ 610,127**	**$ 82,012**	**$ 16,335**	**$ –**	**$ 708,474**
Financing costs, mainly interest expense	**299,768**	**48,757**	**101,461**	**(14,829)**	**435,157**
Income tax expense (benefit)	**235,743**	**29,287**	**(105,444)**	**–**	**159,586**
Income (loss) from continuing operations	**$ 466,307**	**$ 86,092**	**$ 16,838**	**$ (42,308)**	**$ 526,929**
2003					
Operating revenues from external customers	$5,951,852	$1,685,346	$221,807	$ –	$7,859,005
Intersegment revenues	1,123	10,868	53,866	(65,857)	–
Total revenues	$5,952,975	$1,696,214	$275,673	$ (65,857)	$7,859,005
Depreciation and amortization	$ 625,132	$ 80,688	$ 23,172	$ –	$ 728,992
Financing costs, mainly interest expense	312,432	57,673	104,017	(22,911)	451,211
Income tax expense (benefit)	239,671	31,314	(99,584)	–	171,401
Income (loss) from continuing operations	$ 461,363	$ 94,056	$ 8,000	$ (37,579)	$ 525,840
2002					
Operating revenues from external customers	$5,422,496	$1,340,698	$211,048	$ –	$6,974,242
Intersegment revenues	987	5,396	94,304	(100,684)	3
Total revenues	$5,423,483	$1,346,094	$305,352	$(100,684)	$6,974,245
Depreciation and amortization	$ 646,056	$ 86,142	$ 14,363	$ –	$ 746,561
Financing costs, mainly interest expense	285,673	48,390	125,662	(38,605)	421,120
Income tax expense (benefit)	296,556	44,127	(94,837)	–	245,846
Income (loss) from continuing operations	$ 484,937	$ 88,237	$ 24,682	$ (46,468)	$ 551,388

20. SUMMARIZED QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly unaudited financial data is as follows:

	Quarter ended			
(Thousands of dollars, except per share amounts)	*March 31, 2004 (a)*	*June 30, 2004 (a)*	*Sept. 30, 2004 (a)*	*Dec. 31, 2004 (a)*
Revenue	**$2,280,483**	**$1,796,803**	**$2,008,612**	**$2,259,361**
Operating income	**321,250**	**199,105**	**338,057**	**214,804**
Income from continuing operations	**148,797**	**85,361**	**166,183**	**126,589**
Discontinued operations – income (loss)	**1,114**	**945**	**(119,463)**	**(53,564)**
Net income	**149,911**	**86,306**	**46,720**	**73,025**
Earnings available for common shareholders	**148,851**	**85,246**	**45,660**	**71,964**
Earnings per share from continuing operations – basic	**$ 0.37**	**$ 0.21**	**$ 0.41**	**$ 0.31**
Earnings (loss) per share from continuing operations – diluted	**$ 0.36**	**$ 0.21**	**$ 0.40**	**$ 0.30**
Earnings (loss) per share from discontinued operations – basic	**$ –**	**$ –**	**$ (0.30)**	**$ (0.13)**
Earnings (loss) per share from discontinued operations – diluted	**$ –**	**$ –**	**$ (0.28)**	**$ (0.13)**
Earnings per share total – basic	**$ 0.37**	**$ 0.21**	**$ 0.11**	**$ 0.18**
Earnings per share total – diluted	**$ 0.36**	**$ 0.21**	**$ 0.12**	**$ 0.17**

	Quarter ended			
(Thousands of dollars, except per share amounts)	*March 31, 2003 (b)*	*June 30, 2003 (b)*	*Sept. 30, 2003 (b)*	*Dec. 31, 2003 (b)*
Revenue	$2,067,495	$1,703,739	$2,001,600	$2,086,171
Operating income	310,207	170,458	365,888	266,460
Income from continuing operations	128,637	59,625	184,648	152,930
Discontinued operations – income (loss)	11,375	(342,187)	102,847	324,517
Net income (loss)	140,012	(282,562)	287,495	477,447
Earnings (loss) available for common shareholders	138,952	(283,622)	286,435	476,386
Earnings per share from continuing operations – basic	$ 0.32	$ 0.15	$ 0.46	$ 0.39
Earnings per share from continuing operations – diluted	$ 0.31	$ 0.14	$ 0.44	$ 0.37
Earnings (loss) per share from discontinued operations – basic	$ 0.03	$ (0.86)	$ 0.26	$ 0.81
Earnings (loss) per share from discontinued operations – diluted	$ 0.03	$ (0.82)	$ 0.25	$ 0.77
Earnings (loss) per share total – basic	$ 0.35	$ (0.71)	$ 0.72	$ 1.20
Earnings (loss) per share total – diluted	$ 0.34	$ (0.68)	$ 0.69	$ 1.14

(a) 2004 results include special charges in fourth quarter, as discussed in Note 2 to the Consolidated Financial Statements, and unusual items as follows:

- *Results from continuing operations were decreased by the accrual of legal settlements incurred by the holding company in the amount of $17.6 million in the fourth quarter.*
- *Third-quarter results from discontinued operations were decreased by $112 million, or 27 cents per share, due to the estimated impairment expected to result from the disposal of Seren, as discussed in Note 3 to the Consolidated Financial Statements. During fourth quarter, an adjustment increasing the impairment by $31 million, or 7 cents per share, was recorded.*
- *Fourth-quarter results from discontinued operations were decreased by $16 million, or 4 cents per share, related to a reduction of the NRG tax benefits previously booked, after completion of an NRG tax basis study.*
- *Fourth-quarter results from continuing operations were increased by $36 million, or 8 cents per share, due to the accrual of income tax benefits, including $28.9 million related to the successful resolution of various IRS audit issues and other adjustments to current and deferred taxes related to prior years, $4.4 million for the 2003 return-to-accrual true-up and $2.7 million for revisions to benefits related to asset and foreign power sales.*
- *Fourth-quarter results from continuing operations were decreased by an accrual recorded to reflect SPS' best estimate of any potential liability for the impact of its retail fuel cost recovery proceeding in Texas.*

(b) 2003 results include special charges in certain quarters, as discussed in Note 2 to the Consolidated Financial Statements, and unusual items as follows:

- *Results from continuing operations were decreased for NRG-related restructuring costs incurred by the holding company in the amount of $1.4 million in the first quarter, $7.3 million in the second quarter and $3.0 million in the third quarter.*
- *Fourth-quarter results from continuing operations were increased by $22 million, or 3 cents per share, for adjustments made to depreciation accruals for the year, due to a regulatory decision approving the extension of NSP-Minnesota's Prairie Island nuclear plant to operate over the license term.*
- *Fourth-quarter results from continuing operations were increased by $30 million, or 7 cents per share, from the resolution of income tax audit issues related to prior years.*
- *Fourth-quarter results from continuing operations were decreased by $7 million pretax, or 1 cent per share, for charges recorded related to the TRANSLink project due to regulatory and operating uncertainties.*
- *Fourth-quarter results from discontinued operations were increased by $111 million, or 26 cents per share, for reversal of equity in prior NRG losses due to the divestiture of NRG in December 2003, and increased by $288 million, or 68 cents per share, due to revisions to the estimated tax benefits related to Xcel Energy's investment in NRG. See Note 3 to the Consolidated Financial Statements for further discussion of these items.*
- *Fourth-quarter results from discontinued operations were decreased by $59 million, or 14 cents per share, due to the estimated impairment expected to result from the disposal of Xcel Energy International's Argentina assets, as discussed in Note 3 to the Consolidated Financial Statements, and by $16 million, or 4 cents per share, due to the accrual of e prime's cost to settle an investigation by the Commodity Futures Trading Commission.*

SHAREHOLDER INFORMATION

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New York, New York 10286

1-877-778-6786, toll free
This is an automated phone system to expedite requests. However, staying on the line to speak with a representative is an option. Representatives are available from 7 a.m. to 7 p.m. CST.

REPORTS AVAILABLE ONLINE

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

STOCK EXCHANGE LISTINGS AND TICKER SYMBOL

Common stock is listed on the New York, Chicago and Pacific exchanges under the ticker symbol XEL. The New York Stock Exchange lists some of Xcel Energy's preferred stock. In newspaper listings, it appears as XcelEngy.

INVESTOR RELATIONS

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

SHAREHOLDER SERVICES

Internet address: www.xcelenergy.com or contact Dianne Perry, Manager, Shareholder Services, at 612-215-4534 or e-mail dianne.g.perry@xcelenergy.com.

CORPORATE GOVERNANCE

Xcel Energy has filed certifications of its Chief Executive Officer and Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act of 2002 as exhibits to its Annual Report on Form 10-K for 2004 that it has filed with the Securities and Exchange Commission. It has also filed with the New York Stock Exchange the CEO certification for 2004 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 Stocks
The Bank of New York, 101 Barclay Street, New York, New York 10286

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

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UnitedHealth Group Inc.

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Xcel Energy Inc.

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

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General Counsel
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CH2M Hill Companies Ltd.

Dr. Margaret R. Preska [1, 4]
President Emerita
Minnesota State University – Mankato
Distinguished Service Professor
Minnesota State Universities

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

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

* *Wayne H. Brunetti and Richard C. Kelly are ex officio members of all committees.*

XCEL ENERGY PRINCIPAL OFFICERS

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Vice President and Chief Information Officer

Cathy J. Hart
Vice President and Corporate Secretary

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President and Chief Operating Officer

Cynthia L. Lesher
Vice President and Chief Administrative Officer

Teresa S. Madden
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George E. Tyson II
Vice President and Treasurer

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President – Customer and Field Operations

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