XCEL ENERGY INC
Form 10-K
February 24, 2012

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

or

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

Commission File Number: 1-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

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

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

Registrant’s telephone number, including area code: 612-330-5500

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

Title of each class	Name of each exchange on which registered
Common Stock, $2.50 par value per share	New York
$7.60 Junior Subordinated Notes, Series due 2068	New York

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). xYes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
x Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller Reporting Company

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

As of June 30, 2011, the aggregate market value of the voting common stock held by non-affiliates of the Registrants was $11,774,380,709 and there were 484,542,416 shares of common stock outstanding.

As of Feb. 21, 2012, there were 486,828,501 shares of common stock outstanding, $2.50 par value.

DOCUMENTS INCORPORATED BY REFERENCE

The Registrant's Definitive Proxy Statement for its 2012 Annual Meeting of Shareholders is incorporated by reference into Part III of this Form 10-K.

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PART I

Item 1 — Business

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

Xcel Energy Inc.'s Subsidiaries and Affiliates (current and former)	
Cheyenne	Cheyenne Light, Fuel and Power Company
Eloigne	Eloigne Company
NCE	New Century Energies, Inc.
NMC	Nuclear Management Company, LLC
NSP-Minnesota	Northern States Power Company, a Minnesota corporation
NSP System	The integrated electric production and transmission system of NSP-Minnesota and NSP-Wisconsin managed by NSP-Minnesota
NSP-Wisconsin	Northern States Power Company, a Wisconsin corporation
PSCo	Public Service Company of Colorado
PSRI	P.S.R. Investments, Inc.
Seren	Seren Innovations, Inc., a wholly owned subsidiary formerly a broadband communications network
SPS	Southwestern Public Service Co.
UE	Utility Engineering Corporation, an engineering, construction and design company
Utility subsidiaries	NSP-Minnesota, NSP-Wisconsin, PSCo and SPS
WGI	WestGas InterState, Inc.
WYCO	WYCO Development LLC
Xcel Energy	Xcel Energy Inc. and its subsidiaries

Federal and State Regulatory Agencies	
ASLB	Atomic Safety and Licensing Board
CPUC	Colorado Public Utilities Commission
DOE	United States Department of Energy
DOER	Division of Energy Resources (formerly the Office of Energy Security)
DOI	United States Department of the Interior
DOT	United States Department of Transportation
EIB	New Mexico Environmental Improvement Board
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPCA	Minnesota Pollution Control Agency
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NMED	New Mexico Environment Department
NMPRC	New Mexico Public Regulation Commission
NRC	Nuclear Regulatory Commission
OCC	Colorado Office of Consumer Counsel
PSCW	Public Service Commission of Wisconsin
PUCT	Public Utility Commission of Texas

SDPUC	South Dakota Public Utilities Commission
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Electric, Purchased Gas and Resource Adjustment Clauses	
CIP	Conservation improvement program
DSM	Demand side management
DSMCA	Demand side management cost adjustment
ECA	Retail electric commodity adjustment
EECRF	Energy efficiency cost recovery factor

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EIR	Environmental improvement rider
FCA	Fuel clause adjustment
FPPCAC	Fuel and purchased power cost adjustment clause
GAP	Gas affordability program
GCA	Gas cost adjustment
MCR	Mercury cost recovery rider
OATT	Open access transmission tariff
PCCA	Purchased capacity cost adjustment
PCRF	Power cost recovery factor
PGA	Purchased gas adjustment
PSIA	Pipeline system integrity adjustment
QSP	Quality of service plan
RDF	Renewable development fund
RES	Renewable energy standard
RESA	Renewable energy standard adjustment
SCA	Steam cost adjustment
SEP	State energy policy
TCA	Transmission cost adjustment
TCR	Transmission cost recovery adjustment
TCRF	Transmission cost recovery factor

Other Terms and Abbreviations

AFUDC	Allowance for funds used during construction
ALJ	Administrative law judge
APBO	Accumulated postretirement benefit obligation
ARC	Aggregator of retail customers
ARO	Asset retirement obligation
ASU	FASB Accounting Standards Update
BART	Best available retrofit technology
CAA	Clean Air Act
CACJA	Clean Air Clean Jobs Act
CAIR	Clean Air Interstate Rule
CapX2020	Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort
CATR	Clean Air Transport Rule
CCN	Certificate of convenience and necessity
CIPS	Critical Infrastructure Protection Standards
CO2	Carbon dioxide
Codification	FASB Accounting Standards Codification
COLI	Corporate owned life insurance
CON	Certificate of need
CPCN	Certificate of public convenience and necessity
CSAPR	Cross-State Air Pollution Rule
CWIP	Construction work in progress
DSPP	Direct stock purchase plan
EEI	Edison Electric Institute
EGU	Electric generating unit
EPS	Earnings per share

ERRP	Early retiree reimbursement program
ETR	Effective tax rate
FASB	Financial Accounting Standards Board
FTR	Financial transmission right
GAAP	Generally accepted accounting principles
GHG	Greenhouse gas
IFRS	International Financial Reporting Standards
LLW	Low-level radioactive waste
LNG	Liquefied natural gas
MACT	Maximum achievable control technology
MERP	Metropolitan Emissions Reduction Project

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MGP	Manufactured gas plant
MISO	Midwest Independent Transmission System Operator, Inc.
MRO	Midwest Reliability Organization
MVP	Multi-value project
Native load	Customer demand of retail and wholesale customers that a utility has an obligation to serve under statute or long-term contract
NEI	Nuclear Energy Institute
NOL	Net operating loss
NOx	Nitrogen oxide
NOV	Notice of violation
NTC	Notifications to construct
O&M	Operating and maintenance
OCI	Other comprehensive income
PBRP	Performance-based regulatory plan
PCB	Polychlorinated biphenyl
PFS	Private Fuel Storage, LLC
PJM	PJM Interconnection, LLC
PPA	Purchased power agreement
Provident	Provident Life & Accident Insurance Company
PRP	Potentially responsible party
PSP	Performance share plan
PV	Photovoltaic
REC	Renewable energy credit
RECB	Regional expansion criteria benefits
ROE	Return on equity
ROFR	Right of first refusal
RPS	Renewable portfolio standards
RSG	Revenue sufficiency guarantee
RTO	Regional Transmission Organization
SCR	Selective catalytic reduction
SIP	State implementation plan
SO2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
Standard & Poor’s	Standard & Poor’s Ratings Services
TSR	Total shareholder return
WECC	Western Electricity Coordinating Council
WTMPA	West Texas Municipal Power Agency

Measurements

Bcf	Billion cubic feet
KV	Kilovolts
KWh	Kilowatt hours
Mcf	Thousand cubic feet
MMBtu	Million British thermal units
MW	Megawatts
MWh	Megawatt hours

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COMPANY OVERVIEW

Xcel Energy Inc. is a holding company with subsidiaries engaged primarily in the utility business. In 2011, Xcel Energy Inc.'s continuing operations included the activity of four wholly owned utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, and serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipelines, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.

Xcel Energy Inc. was incorporated under the laws of Minnesota in 1909. Xcel Energy's executive offices are located at 414 Nicollet Mall, Minneapolis, Minn. 55401. Its website address is www.xcelenergy.com. Xcel Energy makes available, free of charge through its website, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The public may read and copy any materials that Xcel Energy files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

Xcel Energy's corporate strategy focuses on three core objectives: obtain stakeholder alignment; invest in our regulated utility businesses; and earn a fair return on our utility investments. Xcel Energy files periodic rate cases and establishes formula rates or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations. Environmental leadership is a priority for Xcel Energy and is designed to meet customer and policy maker expectations while creating shareholder value.

NSP-Minnesota

NSP-Minnesota is an operating utility primarily engaged in the generation, purchase, transmission, distribution and sale of electricity in Minnesota, North Dakota and South Dakota. The wholesale customers served by NSP-Minnesota comprised approximately 5 percent of its total KWh sold in 2011. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. NSP-Minnesota provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 0.5 million customers. Approximately 89 percent of NSP-Minnesota's retail electric operating revenues were derived from operations in Minnesota during 2011. Although NSP-Minnesota's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Minnesota's large commercial and industrial electric sales include customers in the following industries: petroleum and coal, as well as food products. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: real estate and educational services. Generally, NSP-Minnesota's earnings contribute approximately 35 percent to 45 percent of Xcel Energy's consolidated net income.

The electric production and transmission costs of the entire NSP System are shared by NSP-Minnesota and NSP-Wisconsin. A FERC-approved Interchange Agreement between the two companies provides for the sharing of all generation and transmission costs of the NSP System. Such costs include current and potential obligations of NSP-Minnesota related to its nuclear generating facilities.

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

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NSP-Wisconsin

NSP-Wisconsin is an operating utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. The wholesale customers served by NSP-Wisconsin comprised approximately 8 percent of its total KWh sold in 2011. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in the same service territory. NSP-Wisconsin provides electric utility service to approximately 251,000 customers and natural gas utility service to approximately 107,000 customers. Approximately 98 percent of NSP-Wisconsin's retail electric operating revenues were derived from operations in Wisconsin during 2011. Although NSP-Wisconsin's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of NSP-Wisconsin's large commercial and industrial electric sales include customers in the following industries: food products, paper and allied products, electric and gas, as well as electronics. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: educational services and grocery and dining establishments. Generally, NSP-Wisconsin's earnings contribute approximately 5 percent to 10 percent of Xcel Energy's consolidated net income.

The management of the electric production and transmission system of NSP-Wisconsin is integrated with NSP-Minnesota.

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

PSCo

PSCo is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in Colorado. The wholesale customers served by PSCo comprised approximately 19 percent of its total KWh sold in 2011. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. PSCo provides electric utility service to approximately 1.4 million customers and natural gas utility service to approximately 1.3 million customers. All of PSCo's retail electric operating revenues were derived from operations in Colorado during 2011. Although PSCo's large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of PSCo's large commercial and industrial electric sales include customers in the following industries: fabricated metal products, as well as electric and gas services. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: real estate and dining establishments. Generally, PSCo's earnings contribute approximately 45 percent to 55 percent of Xcel Energy's consolidated net income.

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

SPS

SPS is an operating utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Texas and New Mexico. The wholesale customers served by SPS comprised approximately 38 percent of its total KWh sold in 2011. SPS provides electric utility service to approximately 376,000 retail customers in Texas and New Mexico. Approximately 74 percent of SPS' retail electric operating revenues were derived from operations in Texas during 2011. Although SPS' large commercial and industrial electric retail customers are comprised of many diversified industries, a significant portion of SPS' large commercial and industrial electric sales include customers in the oil and gas extraction industry. For small commercial and industrial customers, significant electric retail sales include customers in the following industries: oil and gas extraction and crop related agricultural industries. Generally, SPS' earnings contribute approximately 5 percent to 15 percent of Xcel Energy's consolidated net income.

Other Subsidiaries

WGI is a small interstate natural gas pipeline company engaged in transporting natural gas from the PSCo system near Chalk Bluffs, Colo., to the Cheyenne system near Cheyenne, Wyo.

WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. The gas pipeline and storage facilities are leased under a FERC-approved agreement to CIG.

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

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

Xcel Energy conducts its utility business in the following reportable segments: regulated electric utility, regulated natural gas utility and all other. See Note 16 to the consolidated financial statements for further discussion relating to comparative segment revenues, income from continuing operations and related financial information.

Seasonality

The demand for electric power generation and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer and winter months, and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energy's operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. See Item 7 — Management's Discussion of Financial Condition and Results of Operations.

Competition

Xcel Energy's industrial and large commercial customers have the ability to own or operate facilities to generate their own electricity. In addition, customers may have the option of substituting other fuels, such as natural gas, steam or chilled water for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost region. The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a result, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. Xcel Energy Inc.'s utility subsidiaries also have franchise agreements with certain cities subject to periodic renewal. If a city elected not to renew the franchise agreement, it could seek alternative means, such as municipalization. While each of Xcel Energy Inc.'s utility subsidiaries faces these challenges, their rates are competitive with currently available alternatives.

ELECTRIC UTILITY OPERATIONS

NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's operations are regulated by the MPUC, the NDPSC and the SDPUC within their respective states. The MPUC also has regulatory authority over security issuances, property transfers, mergers, dispositions of assets and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's electric resource plans for meeting customers' future energy needs. The MPUC also certifies the need for generating plants greater than 50 MW and transmission lines greater than 100 KV that will be located within the state. No large power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MPUC. The NDPSC and SDPUC have regulatory authority over generation and transmission facilities, along with the siting and routing of new generation and transmission facilities in North Dakota and South Dakota, respectively.

NSP-Minnesota is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric licensing, accounting practices, wholesale sales for resale, transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transfers and mergers, and natural gas transactions in interstate commerce. NSP-Minnesota has requested continued authorization from the FERC to make wholesale electric sales at market-based prices. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion. NSP-Minnesota is a transmission owning member of the MISO RTO.

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

- CIP — The CIP recovers the costs of programs that help customers save energy. CIP includes a comprehensive list of programs that benefit all customers including Saver's Switch®, energy efficiency rebates and energy audits.
- EIR — The EIR recovers the costs of environmental improvements to the A.S. King, High Bridge and Riverside plants, which were renovated under the MERP program.
- GAP — The GAP is a surcharge billed to all non-interruptible customers to recover the costs of offering a low-income customer co-pay program designed to reduce natural gas service disconnections.
- RDF — The RDF allocates money collected from retail customers to support the research and development of emerging renewable energy projects and technologies.
- RES — The RES is a rider that recovers the costs of new renewable generation.
- SEP — The SEP recovers costs related to various energy policies approved by the Minnesota legislature.
- TCR — The TCR recovers costs associated with new investments in electric transmission.

NSP-Minnesota has requested that the recovery of the costs associated with the EIR and RES be included in base rates, which is included in the Minnesota electric rate case currently pending approval with the MPUC.

NSP-Minnesota's retail electric rates in Minnesota, North Dakota and South Dakota include a FCA for monthly billing adjustments for changes in prudently incurred cost of fuel, fuel related items and purchased energy. NSP-Minnesota is permitted to recover these costs through FCA mechanisms approved by the regulators in each jurisdiction. The FCA allows NSP-Minnesota to bill customers for the cost of fuel and related costs used to generate electricity at its plants and energy purchased from other suppliers. In general, capacity costs are not recovered through the FCA. In addition, costs associated with MISO are generally recovered through either the FCA or through rate cases.

Minnesota state law requires electric utilities to invest 1.5 percent of their state revenues in CIP, except NSP-Minnesota, which is required by law to invest 2 percent. These costs are recovered through an annual cost-recovery mechanism for electric conservation and energy management program expenditures.

Capacity and Demand

Uninterrupted system peak demand for the NSP System's electric utility for each of the last three years and the forecast for 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
NSP System	8,615	9,131	9,792	9,213

The peak demand for the NSP System typically occurs in the summer. The 2011 uninterrupted system peak demand for the NSP System occurred on July 18, 2011. The 2011 peak demand occurred on a day with extremely high temperatures and humidity, which resulted in the highest uninterrupted system peak demand since July 31, 2006.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — NSP-Minnesota has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. NSP-Minnesota also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — In addition to using their integrated transmission system, NSP-Minnesota and NSP-Wisconsin have contracts with MISO and regional transmission service providers to deliver power and energy to the NSP System.

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NSP System Resource Plans — In December 2011, NSP-Minnesota filed an update to the 2011 through 2025 resource plan with the MPUC. To account for slower economic growth and the loss of NSP-Wisconsin's wholesale customers, NSP-Minnesota modified the five-year plan to include a recommendation to withdraw the Black Dog repowering project CON and to reassess the wind procurement plan and resource contingency plan in detail. The resource plan update also notified the MPUC that there have been changes in the size, timing, and cost estimates for the extended power uprate projects at the Prairie Island nuclear plant. As a result of these changes, NSP-Minnesota has notified the MPUC that it is completing a new economic and project design analysis and will submit a Change in Circumstances filing seeking reaffirmation of the CON approval before proceeding with the project. Some elements of the resource plan remain unchanged such as the extension of certain contracts, the Monticello nuclear generating plant extended power uprate project and the commitment to specific CIP program annual achievements.

NSP-Minnesota CapX2020 CON — In 2009, the MPUC granted CONs to construct one 230 KV electric transmission line and three 345 KV electric transmission lines as part of the CapX2020 project. The estimated cost of the four major transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total cost. The remainder of the costs will be born by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

NSP-Minnesota and Great River Energy filed four route permit applications with the MPUC in addition to a facility permit application with the SDPUC, a certificate of corridor compatibility application with the NDPSC and a CPCN application with the PSCW. The MPUC has issued route permits for the Minnesota portion of the Fargo, N.D. to St. Cloud, Minn. project and the Bemidji, Minn. to Grand Rapids, Minn. project. The remaining required permit activities are on-going in North Dakota, Wisconsin and Minnesota.

In December 2011, the Monticello, Minn. to St. Cloud, Minn. project was placed in service and MISO granted the final approval of the Brookings, S.D. project as an MVP.

Black Dog Repowering CON — In March 2011, NSP-Minnesota filed a request with Minnesota regulators to approve a CON for the project to retire its last two coal-burning units (Units 3 and 4) at the Black Dog plant in Burnsville, Minn. and replace them with combined-cycle natural gas burning units. Units 1 and 2 were converted to natural gas combined-cycle operation in 2002.

In December 2011, NSP-Minnesota requested to withdraw the CON and close the docket. The request to withdraw is pending an ALJ decision. NSP-Minnesota will reevaluate the Black Dog repowering project as part of the next resource plan expected in 2013.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. LLW consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

LLW Disposal — LLW from NSP-Minnesota's Monticello and Prairie Island nuclear plants is currently disposed at the Clive facility located in Utah. If off-site LLW disposal facilities become unavailable, NSP-Minnesota has storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their current licensed lives.

High-Level Radioactive Waste Disposal — The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility.

Nuclear Geologic Repository - Yucca Mountain Project

In 2002, the U.S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository. In 2008, the DOE submitted an application to construct a deep geologic repository at this site to the NRC. In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC to approve the withdrawal of the application. A number of parties have challenged the DOE's authority to stop the project and withdraw the application. The utility industry, including Xcel Energy, is represented in the challenges by the NEI. In light of the DOE's plan to stop the project and withdraw its application, Xcel Energy in a separate action has requested the Secretary of Energy to set the fee collection rate for the Nuclear Waste Fund to zero until a definitive program is in place. In April 2010, the NEI, on behalf of its members, including Xcel Energy, filed a lawsuit against the DOE in federal court, requesting that the fee be suspended. The Secretary of Energy has convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposal of used nuclear fuel. On Jan. 26, 2012, the Blue Ribbon Commission report was issued. The report provides numerous policy recommendations that will be considered by the Secretary of Energy.

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In June 2010, the ASLB issued a ruling that the DOE could not withdraw the Yucca Mountain application. In September 2011, the NRC announced that it was evenly divided on whether to take the affirmative action of overturning or upholding the ASLB decision. Because the NRC could not reach a decision, an order was issued instructing that information associated with the ASLB adjudication should be preserved. The ASLB complied and the proceeding has been suspended.

Nuclear Spent Fuel Storage
In July 2011, a settlement agreement resolving the method by which NSP-Minnesota can recover certain incremental spent fuel storage costs through 2013 was approved with the DOE. The settlement does not address costs for used fuel storage after 2013; such costs could be the subject of future litigation. NSP-Minnesota received a $100 million payment in August 2011, of which $14.5 million was allocated to NSP-Wisconsin. As of Dec. 31, 2011, NSP-Minnesota has recorded the payment as restricted cash and a regulatory liability. Additionally, a claim for incremental spent fuel storage costs from 2009-2010 was submitted to the DOE in September 2011 and a claim for 2011 will be submitted to the DOE in May 2012.

NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. As of Dec. 31, 2011, there were 29 casks loaded and stored at the Prairie Island plant and 10 canisters loaded and stored at the Monticello plant.

PFS — NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 2006, the U.S. Department of the Interior issued two findings: (1) that it would not grant the leases for rail or intermodal sites and (2) that it was revoking its previous conditional approval of the site lease between PFS and the Skull Valley Indian tribe. In 2007, PFS and the Skull Valley Band filed a lawsuit challenging these actions. The lawsuit remains pending. A judicial appeal of the NRC licensing decision has been held in abeyance pending the outcome of the lawsuit challenging the DOI decisions. The existence of PFS as a licensed out-of-state storage option remains a credible alternative if PFS and the Skull Valley Band can prevail in the pending litigation and if the federal government fails to make progress with their obligation to take title and remove spent nuclear fuel from all domestic reactor sites.

See Note 14 to the consolidated financial statements for further discussion regarding the nuclear generating plants.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear plants. The event at the nuclear plant in Fukushima, Japan could impact the NRC's deliberations on NSP-Minnesota's power uprates discussed below. This event could also result in additional regulation by the NRC, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force to develop recommendations for NRC consideration on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures and licensing processes.

In July 2011, the task force released its recommendations. The report confirmed the safety of U.S. nuclear energy facilities and recommends actions to enhance U.S. nuclear plant readiness to safely manage severe events. In October 2011, the NRC Staff identified the near-term regulatory actions to be taken and prioritized these recommendations into a three-tiered approach. In December 2011, the NRC Commissioners approved the prioritization of the first tier and second tier recommendations. The NRC Staff and the industry are working to establish guidance to implement the NRC's direction regarding resolution of the Tier 1 recommendations and final action by the NRC on these recommendations is expected in the first half of 2012.

The industry is considering a wide range of strategies to address anticipated NRC regulation. Depending on the approach selected, preliminary estimates range from $20 million to $250 million dollars of capital investment approximately over the next five to eight years to address postulated safety upgrades to the Xcel Energy nuclear facilities. The low end of this range would apply if the NRC accepts the industry's 'flex' approach which provides diverse and portable sources of providing emergency power and water. The high end estimate considers added cost of requiring permanently installed modifications with a higher degree of engineering analysis to meet nuclear standards for flooding, seismic and other local environmental considerations. Xcel Energy believes the costs of implementing these requirements would be recoverable through regulatory mechanisms, and it does not expect a material impact on its results of operations.

To better coordinate response activities, the U.S. nuclear energy industry has created a steering committee made up of representatives from major electric sector organizations, including Xcel Energy, to integrate and coordinate the industry's ongoing responses. In addition, the NRC has conducted technical inspections at Xcel Energy's nuclear facilities to assess the capability to respond to extraordinary consequences similar to those that occurred at Fukushima, Japan. These inspections identified no significant findings or issues.

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Nuclear Plant Power Uprates and Life Extension

Life Extensions — In 2006, the NRC renewed the Monticello operating license allowing the plant to operate until 2030. In June 2011, the NRC issued renewed operating licenses for Prairie Island Units 1 and 2, allowing Unit 1 to operate until 2033 and Unit 2 until 2034.

Monticello Nuclear Plant Extended Power Uprate — In 2008, NSP-Minnesota filed for both state and federal approvals of an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello nuclear plant. The MPUC approved the CON for the extended power uprate in 2008. The filing was placed on hold by the NRC Staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. NSP-Minnesota has been working with the industry and regulatory agencies to address this issue and had expected to receive a regulatory decision on the license application in 2012. In October 2011, the Advisory Committee recommended that all licensing actions that credit the use of containment accident pressure be suspended until the causes and risks of Japan's Fukushima incident are better understood. NSP-Minnesota is evaluating the impact of this recommendation on the timing of the license decision which will likely result in a delay of the approval. NSP-Minnesota has rescheduled the remaining equipment changes needed to complete the Monticello power uprate project during the planned spring 2013 refueling outage.

Prairie Island Nuclear Extended Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2, which the MPUC approved in 2009. Analysis of recent extended power uprate submittals to the NRC concluded that significant additional design work beyond current schedule and cost plan estimates are now being required to submit a successful application. As a result, NSP-Minnesota is completing an economic and new project design analysis to determine project impacts and anticipates submitting a Change in Circumstances filing with the MPUC in the first quarter of 2012.

Total capital investment between 2012 and 2015 for the Monticello and Prairie Island power uprate and life cycle management activities is estimated to be approximately $640 million.

Fuel Supply and Costs

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

NSP System Generating Plants	Coal* Cost	Coal* Percent	Nuclear Cost	Nuclear Percent	Natural Gas Cost	Natural Gas Percent	Weighted Average Fuel Cost
2011	$2.06	55 %	$0.89	40 %	$6.56	5 %	$ 1.82
2010	1.89	51	0.83	42	6.29	7	1.73
2009	1.78	57	0.70	39	7.36	4	1.61

* Includes refuse-derived fuel and wood.

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — The NSP System normally maintains approximately 40 days of coal inventory. Coal supply inventories at Dec. 31, 2011 and 2010 were approximately 48 and 39 days usage, respectively. NSP-Minnesota's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Wyoming and

Montana. During 2011 and 2010, coal requirements for the NSP System's major coal-fired generating plants were approximately 9.5 million tons. The estimated coal requirements for 2012 are approximately 8 million tons, including adjustments to account for Sherco Unit 3, which was shut down in November 2011 after experiencing a significant failure of its turbine, generator, and exciter systems. It is uncertain when Sherco Unit 3 will recommence operations.

NSP-Minnesota and NSP-Wisconsin have contracted for coal supplies to provide 99 percent of their coal requirements in 2012, and a declining percentage of the requirements in subsequent years. The NSP System's general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

NSP-Minnesota and NSP-Wisconsin have a number of coal transportation contracts that provide for delivery of 100 percent of their coal requirements in 2012 and 2013. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather and availability of equipment.

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Nuclear — To operate NSP-Minnesota's nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium and long-term contracts for uranium concentrates, conversion services and enrichment services with multiple producers and with a focus on diversification to minimize potential impacts caused by supply interruptions due to geographical and world political issues.

- Current nuclear fuel supply contracts cover 100 percent of uranium concentrates requirements through 2017 and approximately 66 percent of the requirements for 2018 through 2025.
- Current contracts for conversion services cover 100 percent of the requirements through 2017 and approximately 78 percent of the requirements for 2018 through 2025.
- Current enrichment service contracts cover 100 percent of the requirements through 2016 and approximately 95 percent of the requirements for 2017 through 2025.

Fabrication services for Monticello and Prairie Island are 100 percent committed through 2025 and 2014, respectively. A contract for fuel fabrication services for Prairie Island is currently being negotiated for 2015 and beyond.

NSP-Minnesota expects sufficient uranium concentrates, conversion services and enrichment services to be available for the total fuel requirements of its nuclear generating plants. Some exposure to spot market price volatility will remain due to index-based pricing structures contained in some of the supply contracts.

Natural gas — The NSP System uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies and associated transportation and storage services for power plants are procured under contracts with various terms to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, remaining forecasted requirements are able to be procured through a liquid spot market. Generally, natural gas supply contracts have pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC approved transportation tariff rates. These transportation rates are subject to revision based upon FERC approval of changes in the timing or amount of allowable cost recovery by providers. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2010, the NSP System's commitments related to gas supply contracts were $14 million and commitments related to gas transportation and storage contracts were approximately $499 million. At Dec. 31, 2011, the NSP System did not have any commitments related to gas supply contracts; however, commitments related to gas transportation and storage contracts, which expire in various years from 2012 to 2028, were approximately $462 million. The NSP System has limited on-site fuel oil storage facilities and relies on the spot market for incremental supplies, if needed.

Renewable Energy Sources

The NSP System's renewable energy portfolio includes wind, biomass, solar and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 19.7 percent and 18.3 percent of the NSP System's total owned and purchased energy for 2011 and 2010, respectively. Biomass and solar power comprised approximately 2.8 percent and 2.9 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind and hydroelectric sources. As of Dec. 31, 2011, the NSP System is in compliance with its renewable portfolio standards, which require generation from renewable resources of 15 percent and 8.89 percent of Minnesota and Wisconsin electric retail sales, respectively.

The NSP System also offers customer-focused renewable energy initiatives. The Windsource® program allows customers in Minnesota and Wisconsin to purchase a portion or all of their electricity from renewable sources. Approximately 22,715 and 22,676 customers purchased 176,522 MWh and 166,979 MWh of electricity under the Windsource program in 2011 and 2010, respectively. Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards® program. Over 300 PV systems with approximately 3 MW of aggregate capacity and 166 PV systems with approximately 1 MW of aggregate capacity have been installed in Minnesota under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

Wind — The NSP System acquires the majority of its wind energy from purchased power agreements with wind farm owners, primarily in Southwestern Minnesota. The NSP System currently has more than 100 of these agreements in place, with facilities ranging in size from under 1 MW to more than 200 MW. In addition to receiving purchased wind energy under these agreements, the NSP System also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under these contracts was approximately $39 and $37 for 2011 and 2010, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state specific renewable resource requirements, and the year of contract execution.

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Generally, contracts executed in 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012.

The NSP System also fully owns and operates two wind farms. The 101 MW Grand Meadow Wind Farm began generating electricity in 2008 and the 201 MW Nobles Wind Farm began generating electricity in 2010. Collectively, the NSP System had over 1,600 MW and nearly 1,500 MW of wind energy on its system at the end of 2011 and 2010, respectively. Wind energy comprised 9.4 percent and 8.0 percent of the total owned and purchased energy on the NSP System for 2011 and 2010, respectively.

In 2011, NSP-Minnesota agreed to purchase 200 MW of wind power from Geronimo Wind Energy's Prairie Rose Wind Farm, which is expected to be completed in 2012. By the end of 2012, the NSP System plans to have over 1,900 MW of wind energy on its system.

Hydroelectric — The NSP System acquires its hydroelectric energy from both owned generation and purchased power agreements. The NSP System owns 20 hydroelectric plants throughout Wisconsin and Minnesota which provide 253 MW of capacity. For most of 2011, there were eight purchased power agreements in place which provided approximately 24 MW of hydroelectric capacity. In December 2011, an additional nine MW of purchased hydroelectric capacity was brought onto the system. Additionally, the NSP System purchases significant generation from Manitoba Hydro which is sourced primarily from its fleet of hydroelectric facilities. Hydroelectric energy comprised 7.5 percent and 7.4 percent of the total owned and purchased energy on the NSP System for 2011 and 2010, respectively.

Wholesale Commodity Marketing Operations

NSP-Minnesota conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy-related products. See Item 7 for further discussion.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Wisconsin's operations are regulated by the PSCW and the MPSC, within their respective states. In addition, each of the state commissions certifies the need for new generating plants and electric transmission lines before the facilities may be sited and built. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to its wholesale electric operations, hydroelectric generation licensing, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. NSP-Wisconsin has requested continued authorization from the FERC to make wholesale electric sales at market-based prices. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion. NSP-Wisconsin is a transmission owning member of the MISO RTO.

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

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, under Wisconsin rules, utilities must submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities must defer the amount of any fuel cost over-collection or under-collection in excess of a two percent annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW after an opportunity for a hearing. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. These rules went into effect in January 2011.

NSP-Wisconsin's wholesale electric rate schedules include a fuel clause adjustment to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

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

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Wisconsin Energy Efficiency and Conservation Goals — In June 2011, the Wisconsin biennial budget bill was signed into law, which rolled back the projected increases for state energy efficiency and conservation funding effective in 2012. Based on this action, NSP-Wisconsin expects to be allocated approximately $8.2 million of the statewide program costs in 2012, increasing to approximately $9.1 million by 2014. Historically, NSP-Wisconsin has recovered these costs in rate charges to Wisconsin retail customers and expects to recover the program costs in rates going forward.

Capacity and Demand

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Capacity and Demand.

Energy Sources and Related Transmission Initiatives

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Energy Sources and Related Transmission Initiatives.

NSP-Wisconsin CapX2020 CPCN — An application for a CPCN for the Wisconsin portion of the 345 KV CapX2020 project was filed with the PSCW in January 2011. This line is expected to entail construction of approximately 150 miles of new transmission lines between Hampton, Minn. and La Crosse, Wis. with approximately 50 miles located in Wisconsin at an estimated cost of $200 million to NSP-Wisconsin.

In June 2011, the PSCW determined the application was complete, which triggers the 360-day deadline for the PSCW to grant a CPCN for the project. In January 2012, the PSCW Staff issued a final Environmental Impact Statement that raises questions about the need for the project and the applicants preferred routes. There have also been issues raised by the Wisconsin Department of Transportation and the WDNR regarding portions of the proposed route and there are route location alternatives if the PSCW determines these issues warrant such a decision. Testimony was filed in January and February 2012 and public hearings are expected to be held in March 2012. The PSCW is expected to issue a final decision in mid-2012 regarding the transmission line.

Fuel Supply and Costs

NSP-Wisconsin operates an integrated system with NSP-Minnesota. See NSP-Minnesota Fuel Supply and Costs.

PSCo

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — PSCo is regulated by the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is regulated by the FERC with respect to its wholesale electric operations, accounting practices, hydroelectric licensing, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards and natural gas transactions in interstate commerce. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion.

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

- ECA — The ECA recovers fuel and purchased power costs. Short-term sales margins are shared with retail customers through the ECA. The ECA is revised quarterly.
-

PCCA — The PCCA recovers purchased capacity payments. Effective January 2011, the PCCA began to recover the revenue requirement associated with the purchase of the Blue Spruce Energy Center and Rocky Mountain Energy Center. Recovery of the revenue requirement for these facilities will be removed from the PCCA to base rates in mid 2012, as part of the PSCo electric rate case.

- SCA — The SCA recovers the difference between PSCo’s actual cost of fuel and the amount of these costs recovered under its base steam service rates. The SCA rate is revised annually in January, as well as on an interim basis to coincide with changes in fuel costs.
- DSMCA — The DSMCA recovers DSM, interruptible service option credit costs and performance initiatives for achieving various energy savings goals. Beginning 2010, the CPUC approved recovery of the full amount of DSM-related costs through the combination of base rates and a DSMCA tracker mechanism.
- RESA — The RESA recovers the incremental costs of compliance with the RES and is set at its maximum level of 2 percent of the customer’s total bill.
- Wind Energy Service — Wind Energy Service is a premium service for those customers who voluntarily choose to pay an additional charge to increase the level of renewable resource generation used to meet the customer’s load requirements.
- TCA — The TCA recovers transmission plant revenue requirements and allows for a return on CWIP outside of rate cases.

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PSCo recovers fuel and purchased energy costs from its wholesale electric customers through a fuel cost adjustment clause approved by the FERC. PSCo's wholesale customers have agreed to pay the full cost of renewable energy purchase and generation costs through a fuel clause and in exchange receive renewable energy credits associated with those resources.

PBRP and QSP Requirements — PSCo currently operates under an electric PBRP. This regulatory plan includes an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2012. PSCo regularly monitors and records as necessary an estimated customer refund obligation under the PBRP. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually.

Capacity and Demand

Uninterrupted system peak demand for PSCo's electric utility for each of the last three years and the forecast for 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
PSCo	6,311	6,436	6,896	6,313

The peak demand for PSCo's system typically occurs in the summer. The 2011 uninterrupted system peak demand for PSCo occurred on July 18, 2011 and was higher than 2010 and the 2012 forecasted peak demand primarily due to backup load to serve the non-PSCo joint owners of Comanche Unit 3, which was offline when the peak demand occurred.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — PSCo has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. PSCo also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations, or to obtain energy at a lower cost.

Purchased Transmission Services — In addition to using its own transmission system, PSCo has contracts with regional transmission service providers to deliver power and energy to PSCo's customers.

PSCo Resource Plan — In October 2011, PSCo filed the 2011 electric resource plan. Beginning in 2017, PSCo is projected to have relatively low resource needs and has proposed to fill these needs with a competitive resource acquisition process. The CPUC will consider the resource plan in two phases. In the first phase, the CPUC will review planning assumptions, competitive bidding structure, and determine if PSCo should acquire generation technology. The first phase is expected to be completed by the end of 2012. In the second phase, PSCo will conduct the competitive acquisition process, which is expected to be submitted to the CPUC for approval in 2013.

RES Compliance Plan — Colorado has a law that mandates that at least 30 percent of PSCo's energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. PSCo has filed the 2012 and 2013 RES compliance plan. PSCo proposed to acquire up to 30 MW of customer-sited solar projects each year and up to 6 MW of community scale solar projects. A decision on the 2012 and 2013 plan is expected in the first quarter of 2012. PSCo currently recovers any incentives paid through a combination of the ECA and RESA cost-recovery mechanisms.

Solar*Rewards Program — In March 2011, the CPUC approved a settlement that limits the amount of customer sited solar generation that PSCo will purchase, caps the amount PSCo will spend on customer sited solar generation and shifts from up-front payments to pay-for-performance. The settlement gives PSCo a presumption of prudence, for both the existing RESA balance, and the future RESA balance if PSCo performs consistent with the acquisition terms of the settlement.

Separately, the CPUC approved a change to the treatment of REC trading margins that allows the customers' share of the margins through the end of the pilot period, approximately $54 million, to be netted against the RESA regulatory asset balance. During the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

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CACJA — The CACJA required PSCo to file a comprehensive plan to reduce annual emissions of NOx by at least 70 to 80 percent or greater from 2008 levels by 2017 from the coal-fired generation identified in the plan. The plan allows PSCo to propose emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by 2017. The total investment associated with the adopted plan is approximately $1.0 billion through 2017 and the rate impact is expected to increase future bills on average by 2 percent annually.

In December 2010, the CPUC approved the following:

- Shutdown Cherokee Units 2 and 1 in 2011 and 2012, respectively, and Cherokee Unit 3 (365 MW in total) by the end of 2015, after a new natural gas combined-cycle unit is built at Cherokee Station (569 MW);
- Fuel-switch Cherokee Unit 4 (352 MW) to natural gas by 2017;
- Shutdown Arapahoe Unit 3 (45 MW) and fuel-switch Unit 4 (111 MW) in 2014 to natural gas;
- Shutdown Valmont Unit 5 (186 MW) in 2017;
- Install SCR for controlling NOx and a scrubber for controlling SO2 on Pawnee Generating Station in 2014;
- Install SCRs on Hayden Unit 1 in 2015 and Hayden Unit 2 in 2016; and
- Convert Cherokee Unit 2 and Arapahoe Unit 3 to synchronous condensers to support the transmission system.

PSCo has received CPCNs for the conversion of Cherokee Unit 2 to a synchronous condenser, for the decommissioning of Cherokee Unit 1 and Unit 2, and for the Pawnee emissions controls. In addition, PSCo has filed for CPCNs for the new natural gas combined-cycle at Cherokee station and the Hayden emissions controls.

San Luis Valley-Calumet-Comanche Transmission Project — In May 2009, PSCo and Tri-State Generation and Transmission Association filed a joint application with the CPUC for a 230 KV and 345 KV line and substation construction project. The line was intended to assist in bringing solar power in the San Luis Valley to customers. The line was originally expected to be placed in-service in 2013; however, due to delays in the siting and permitting of the line, the in-service date was delayed.

In October 2011, in conjunction with the filing of the electric resource plan, PSCo determined that due to lower projected load growth, lower gas prices and the higher cost of solar thermal generation, it was unlikely to need the transmission line in the foreseeable future. A CPUC decision on the resource plan is expected in late 2012.

SmartGridCity™ CPCN — As part of the PSCo 2010 electric rate case, the CPUC included recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred by PSCo to develop and operate SmartGridCity™, subject to refund, and ordered PSCo to file for a CPCN for that project.

In February 2011, the CPUC approved the CPCN and allowed recovery of approximately $28 million of the capital cost and 100 percent of the O&M costs and ordered PSCo to file for a rate reduction in April 2011 to reflect the lower level of capital in rate base. On July 1, 2011, PSCo implemented an annual rate reduction of $2.8 million. In December 2011, PSCo filed an application addressing the additional information requested. A decision is expected in the third quarter of 2012.

Boulder, Colo. Franchise Agreement — In November 2011, two ballot measures were passed by the citizens of Boulder. The first measure increased the occupation tax to raise an additional $1.9 million annually (and extended the tax until the earlier to occur of (1) Dec. 31, 2017, (2) when Boulder decides not to create a municipal utility, or (3) when Boulder commences delivery of municipal electric utility services) for the purpose of funding the exploration costs of forming a municipal utility and acquiring the PSCo electric distribution system in Boulder. The second measure authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including, but not limited to, the level of initial rates and debt service coverage. Boulder has retained legal counsel specializing in condemnation and plans to retain legal counsel specializing in FERC matters. The City Council has not yet decided whether it will proceed with the formation of a municipal electric utility or with commencing a condemnation proceeding. Should Boulder proceed with these actions and be successful, PSCo would seek to obtain full compensation for the property and business taken by Boulder and for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

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Fuel Supply and Costs

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

	Coal		Natural Gas		Weighted Average
PSCo Generating Plants	Cost	Percent	Cost	Percent	Fuel Cost
2011	$ 1.77	76 %	$ 4.98	24 %	$ 2.54
2010	1.58	85	5.05	15	2.11
2009	1.52	82	3.99	18	1.97

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — PSCo normally maintains approximately 41 days of coal inventory. Coal supply inventories at Dec. 31, 2011 and 2010 were approximately 48 and 34 days usage, respectively. PSCo's generation stations use low-sulfur western coal purchased primarily under contracts with suppliers operating in Colorado and Wyoming. During 2011 and 2010, PSCo's coal requirements for existing plants were approximately 10.5 and 10.7 million tons, respectively. The estimated coal requirements for 2012 are approximately 11.6 million tons.

PSCo has contracted for coal supply to provide 100 percent of its coal requirements in 2012, and a declining percentage of requirements in subsequent years. PSCo's general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years. Remaining requirements will be filled through the procurement process or over-the-counter transactions.

PSCo has coal transportation contracts that provide for delivery of 100 percent of its coal requirements in 2012 and 2013. Coal delivery may be subject to short-term interruptions or reductions due to operation of the mines, transportation problems, weather, and availability of equipment.

Natural gas — PSCo uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo's power plants are procured under contracts to provide an adequate supply of fuel. However, as natural gas primarily serves intermediate and peak demand, any remaining forecasted requirements are able to be procured through a liquid spot market. The majority of natural gas supply under contract is covered by a long-term agreement with Anadarko Energy Services Company, the balance of natural gas supply contracts have pricing features tied to changes in various natural gas indices. PSCo hedges a portion of that risk through financial instruments. See Note 11 to the consolidated financial statements for further discussion. Most transportation contract pricing is based on FERC approved transportation tariff rates. These transportation rates are subject to revision based upon FERC approval of changes in the timing or amount of allowable cost recovery by providers. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2010, PSCo's commitments related to gas supply contracts were approximately $817 million and commitments related to gas transportation and storage contracts were approximately $838 million. At Dec. 31, 2011, PSCo's commitments related to gas supply contracts, which expire in various years from 2012 through 2021, were approximately $730 million and commitments related to gas transportation and storage contracts, which expire in various years from 2012 through 2060, were approximately $819 million.

Renewable Energy Sources

PSCo's renewable energy portfolio includes wind, biomass, solar, and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 14.6 percent and 11.7 percent of PSCo's total owned and purchased energy for 2011 and 2010, respectively. Biomass, solar and hydroelectric power comprised approximately 2.2 percent and 1.4 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind. As of Dec. 31, 2011, PSCo is in compliance with its renewable portfolio standards which require generation from renewable resources of 12 percent of electric retail sales.

PSCo acquires the majority of its wind energy from purchased power agreements with wind farm owners, primarily in Colorado and Wyoming. PSCo currently has 18 of these agreements in place, with facilities ranging in size from under 3 MW to 300 MW. In addition to receiving purchased wind energy under these agreements, PSCo also typically receives wind RECs, which are used to meet state renewable resource requirements. The average cost per MWh of wind energy under these contracts was approximately $45 for each of 2011 and 2010.The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state specific renewable resource requirements, and the year of contract execution.

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Generally, contracts executed in 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012.

In 2011, the new 252 MW Cedar Point Wind Project and the 251 MW Cedar Creek II Wind Farm began commercial operations. PSCo has long-term purchased power agreements to acquire the output of both facilities. PSCo has agreed to purchase 200 MW of wind power from NextEra Energy Resources' Limon Wind Energy Center and an additional 200 MW from NextEra Energy Resources' Limon Wind Energy Center II, which are both expected to be completed in 2012. The average cost over the 25 year term of these contracts is approximately $35 per MWh, which is lower than the average cost per MWh of purchased wind energy on the PSCo system. By the end of 2012, PSCo plans to have approximately 2,200 MW of wind on its system.

Additionally, PSCo owns and operates the 26.4 MW Ponnequin Wind Farm in northern Colorado, which has been in service since 1999. PSCo collectively had nearly 1,800 MW and 1,300 MW of wind energy on its system at the end of 2011 and 2010, respectively. Wind energy comprised 12.4 percent and 10.3 percent of PSCo's total owned and purchased energy for 2011 and 2010, respectively.

PSCo also offers customer-focused renewable energy initiatives. The Windsource program allows customers to purchase a portion or all of their electricity from renewable sources. Approximately 35,843 and 38,762 customers in Colorado purchased 211,511 MWh and 212,900 MWh of electricity under the Windsource program in 2011 and 2010, respectively. Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 9,600 PV systems with approximately 110 MW of aggregate capacity and over 7,100 PV systems with approximately 76 MW of aggregate capacity have been installed in Colorado under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

Wholesale Commodity Marketing Operations

PSCo conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. See Item 7 for further discussion.

SPS

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — The PUCT and NMPRC regulate SPS' retail electric operations and have jurisdiction over its retail rates and services and the construction of transmission or generation in their respective states. The municipalities in which SPS operates in Texas have original jurisdiction over SPS' rates in those communities. Each municipality can deny SPS' rate increase. SPS can then appeal municipal rate decisions to the PUCT, which hears all municipal rate denials in one hearing. The NMPRC also has jurisdiction over the issuance of securities. SPS is regulated by the FERC with respect to its wholesale electric operations, accounting practices, wholesale sales for resale, the transmission of electricity in interstate commerce, compliance with NERC electric reliability standards, asset transactions and mergers, and natural gas transactions in interstate commerce. SPS has received authorization from the FERC to make wholesale electric sales at market-based prices. See Summary of Recent Federal Regulatory Developments - Market-Based Rate Rules for further discussion.

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

- FPPCAC — The FPPCAC adjusts monthly to recover the difference between the actual fuel and purchased power costs and the amount included in base rates of SPS' New Mexico retail jurisdiction.

- EECRF — The EECRF rider recovers costs associated with providing energy efficiency programs in Texas.
- TCRF — The TCRF rider recovers transmission infrastructure improvement costs and changes in wholesale transmission charges. Effective February 2011, the recovery of the costs associated with the TCRF rider were included in base rates and the TCRF rider was set to zero dollars.
- PCRF — The PCRF rider allows recovery of certain purchased power costs. Effective February 2011, the recovery of the costs associated with the PCRF rider are included in base rates, and the PCRF rider was eliminated.

Fuel and purchased energy costs are recovered in Texas through a fixed fuel and purchased energy recovery factor, which is part of SPS' retail electric tariff. Based on regulatory approval in 2011, SO2 and NOx allowance revenues and costs are also recovered through the fixed fuel and purchased energy recovery factor. The regulations allow retail fuel factors to change up to three times per year.

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The fixed fuel and purchased energy recovery factor provides for accounting of over- or under-recovery of fuel and purchased energy expenses. Regulations also require refunding or surcharging over- or under- recovery amounts, including interest, when they exceed four percent of the utility's annual fuel and purchased energy costs on a rolling 12-month basis, if this condition is expected to continue. In the fourth quarter of 2011, a fuel surcharge was implemented in Texas for recovery of the under-recovered fuel and purchased energy costs and interest. The surcharge will remain in place until October 2012.

PUCT regulations require periodic examination of SPS' fuel and purchased energy costs, the efficient use of fuel and purchased energy, the fuel acquisition and management policies and the purchased energy commitments. SPS is required to file an application for the PUCT to retrospectively review fuel and purchased energy costs at least every three years.

NMPRC regulations require SPS to periodically request authority to continue using its FPPCAC. The NMPRC reviews SPS' use of its FPPCAC since the filing of its previous fuel clause continuation filing. As a follow-up to an SPS rate case, the NMPRC conducted an audit of SPS' fuel and purchased power costs for a 12-month period from July 2009 through July 2010 and the tracking mechanism to capture costs and revenues associated with SPS' RECs from assorted wind projects for that period. In December 2011, the NMPRC authorized SPS to continue its use of its FPPCAC and approved the prudency of the use of the FPPCAC for the period through Dec. 31, 2010.

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

Capacity and Demand

Uninterrupted system peak demand for SPS for each of the last three years and the forecast for 2012, assuming normal weather, is listed below.

	System Peak Demand (in MW)			
	2009	2010	2011	2012 Forecast
SPS	5,038	4,985	5,210	5,155

The peak demand for the SPS system typically occurs in the summer. The 2011 uninterrupted system peak demand for SPS occurred on Aug. 2, 2011.

Energy Sources and Related Transmission Initiatives

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

Purchased Power — SPS has contracts to purchase power from other utilities and independent power producers. Long-term purchased power contracts typically require a periodic payment to secure the capacity and a charge for the associated energy actually purchased. SPS also makes short-term purchases to meet system load and energy requirements, to replace generation from company-owned units under maintenance or during outages, to meet operating reserve obligations or to obtain energy at a lower cost.

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

SPS Transmission NTC — In 2010, SPP approved the first of a series of new transmission lines in several states, including Texas, New Mexico and Oklahoma, to help improve electric reliability, strengthen the existing transmission grid and provide outlets for additional renewable wind generation. As a member of SPP, SPS accepts NTCs for SPP identified lines. SPS has accepted NTCs for approximately 119 miles of transmission lines at an estimated cost of $126 million. Under its jurisdiction, the PUCT has thus far approved the construction of two 115 KV and one 230 KV electric transmission line as part of the project at an estimated cost of $29.1 million. These approved transmission lines are expected to be completed in the first half of 2013.

TUCO to Woodward District Extra High Voltage Interchange — In June 2009, SPP directed SPS to construct a 178 mile 345 KV transmission line between Lubbock, Texas and Woodward, Okla. The estimated investment in the new line is $184 million and will be recovered from SPP members, including SPS, in accordance with the SPP OATT and the retail ratemaking process. In March 2011, SPS filed a CCN to build the line with the PUCT. A decision is expected in the first quarter of 2012.

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Jones CCN — In August 2011, the PUCT approved SPS' request for a CCN to build a gas-fired combustion turbine generating unit at SPS' existing Jones Station in Lubbock, Texas (Jones Unit 4). This generating unit will add 168 MW of capacity to the SPS service territory. In February 2012, the NMPRC approved the CCN.

SPS Resource Plans — SPS is required to develop and implement a renewable portfolio plan in which ten percent of its energy to serve its New Mexico retail customers is produced by renewable resources in 2011, increasing to 15 percent in 2015. SPS primarily fulfills its renewable portfolio requirements through the purchase of wind energy. In 2009, the NMPRC granted SPS a variance to allow SPS to delay meeting its solar energy requirement until 2012 provided that SPS compensates for any shortfall of the 2011 solar energy requirement during 2012 through 2014. SPS executed and received NMPRC approval for a total of 50 MW of PV solar energy PPAs. SPS requested and was granted a variance from the NMPRC to extend the time to implement a portion of the diversity requirements to January 2014. SPS is continuing its efforts to acquire viable biomass generation or make a biogas purchase to meet the diversity portion of its renewable energy portfolio plan in New Mexico.

SPS solicited public participation throughout 2011 in its New Mexico 2012 Integrated Resource Planning (IRP) and anticipates filing the IRP with the NMPRC in July 2012.

CSAPR — CSAPR addresses long range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. CSAPR is discussed further at Note 13 to the consolidated financial statements — Environmental Contingencies. Xcel Energy is in the process of determining various scenarios to respond to the CSAPR depending on whether the CSAPR is upheld, reversed, or modified.

If the CSAPR is upheld and unmodified, Xcel Energy believes that the CSAPR could ultimately require the installation of additional emission controls on some of SPS' coal-fired electric generating units. If compliance is required in a short time frame, SPS may be required to redispatch its system to reduce coal plant operating hours, in order to decrease emissions from its facilities prior to the installation of emission controls. The expected cost for these scenarios vary significantly and SPS has estimated capital expenditures of approximately $470 million over the next four years for the CSAPR.

Fuel Supply and Costs

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

	Coal		Natural Gas		Weighted Average
SPS Generating Plants	Cost	Percent	Cost	Percent	Fuel Cost
2011	$ 1.89	67 %	$ 4.37	33 %	$ 2.71
2010	1.84	71	4.59	29	2.64
2009	1.74	73	3.80	27	2.3

See Items 1A and 7 for further discussion of fuel supply and costs.

Fuel Sources

Coal — SPS purchases all of the coal requirements for its two coal facilities, Harrington and Tolk electric generating stations, from TUCO Inc. (TUCO). TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers. The coal supply contract with TUCO expires in 2016 and 2017 for the Harrington station and Tolk station, respectively. As of Dec. 31, 2011 and 2010, coal inventories at SPS were approximately 43 and 41 days supply, respectively. TUCO has coal agreements to supply 96 percent of SPS' coal requirements in 2012, and a declining percentage of the requirements in subsequent years. SPS' general coal purchasing objective is to contract for approximately 100 percent of requirements for the following year, 67 percent of requirements in two years, and 33 percent of requirements in three years.

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Natural gas — SPS uses both firm and interruptible natural gas supply and standby oil in combustion turbines and certain boilers. Natural gas for SPS' power plants is procured under contracts to provide an adequate supply of fuel; which typically is purchased with terms of one year or less. The transportation and storage contracts expire in various years from 2012 to 2033. All of the natural gas supply contracts have pricing that is tied to various natural gas indices. Most transportation contract pricing is based on FERC and Railroad Commission of Texas approved transportation tariff rates. These transportation rates are subject to revision based upon FERC or Railroad Commission of Texas approval of changes in the timing or amount of allowable cost recovery by providers. Certain natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. SPS' commitments related to gas supply contracts were approximately $24 million and $28 million and commitments related to gas transportation and storage contracts were approximately $242 million and $233 million at Dec. 31, 2011 and Dec. 31, 2010, respectively.

Renewable Energy Sources

SPS' renewable energy portfolio includes wind, solar and hydroelectric power from both owned generating facilities and purchased power agreements. Renewable energy comprised 8.2 percent and 7.9 percent of SPS' total owned and purchased energy for 2011 and 2010, respectively. Solar and hydroelectric power comprised approximately 0.4 percent and 0.3 percent of renewable energy for 2011 and 2010, respectively, with the remaining renewable energy provided by wind. As of Dec. 31, 2011, SPS is in compliance with its renewable portfolio standards, which require generation from renewable resources of approximately 3 percent and 10 percent of Texas and New Mexico electric retail sales, respectively.

SPS acquires its wind energy from long-term purchased power agreements with wind farm owners, primarily in the Texas Panhandle area of Texas and New Mexico. SPS currently has six of these agreements in place, with facilities ranging in size from under 2 MW to 161 MW. In addition to receiving purchased wind energy under these agreements, SPS also typically receives wind RECs, which are used to meet state renewable resource requirements. Additionally, SPS is required to purchase another 240 MW of wind energy from qualified generating facilities as defined in the Public Utilities Regulatory Policy Act of 1978. These purchases are made at the SPP Locational Imbalance Price rather than through long term purchased power agreements. The average cost per MWh of wind energy under these contracts was approximately $26 and $27 for 2011 and 2010, respectively. The cost per MWh of wind energy varies by contract and may be influenced by a number of factors including regulation, state specific renewable resource requirements, and the year of contract execution.

Generally, contracts executed in 2011 have benefited from improvements in technology, excess capacity among manufacturers, and motivation to complete new construction prior to expiration of the Federal Production Tax Credits in 2012. At the end of 2011 and 2010, SPS had nearly 700 MW of wind energy on its system.

Additionally, in late 2010, SPS signed an agreement to purchase the output of the 161 MW Spinning Spur Wind Ranch which is expected to be completed in 2012. Wind energy comprised 7.8 percent and 7.6 percent of SPS' total owned and purchased energy for 2011 and 2010, respectively.

SPS also offers customer-focused renewable energy initiatives. The Windsource program allows customers in New Mexico to purchase a portion or all of their electricity from renewable sources. Approximately 1,233 and 1,224 customers purchased 7,005 MWh and 7,162 MWh of electricity under the Windsource program in 2011 and 2010, respectively. Additionally, to encourage the growth of solar energy on the system, customers are offered incentives to install solar panels on their homes and businesses under the Solar*Rewards program. Over 70 PV systems with approximately 5 MW of aggregate capacity and 16 PV systems with less than 1 MW of aggregate capacity have been installed in New Mexico under this program as of Dec. 31, 2011 and Dec. 31, 2010, respectively.

Wholesale Commodity Marketing Operations

SPS conducts various wholesale marketing operations, including the purchase and sale of electric capacity, energy and energy related products. SPS uses physical and financial instruments to minimize commodity price and credit risk and hedge sales and purchases. See Item 7 for further discussion.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries, including enforcement of NERC mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 12 to the accompanying consolidated financial statements for discussion of other regulatory matters.

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FERC Transmission Planning and Cost Allocation — The FERC has approved the open access transmission planning processes for Xcel Energy and the RTOs serving the NSP System and SPS (MISO and SPP, respectively) set forth in tariffs filed in compliance with FERC Order 890. The FERC has also approved SPP tariffs providing for the partial regional allocation of the cost of new transmission facilities.

In July 2011, the FERC issued Order 1000 adopting modified rules for regional transmission planning, wholesale transmission cost allocation and transmission development. The new rules would eliminate any preferential right at the federal level for an incumbent transmission provider to construct transmission facilities subject to regional cost allocation, referred to as a ROFR. The transmission planning processes will be subject to additional tariff revisions subsequent to Order 1000 compliance filings due in October 2012.

Order 1000 will require significant changes in transmission planning and cost allocation mechanisms in the WestConnect where PSCo is located. The impacts of the provisions of Order 1000 regarding transmission planning and cost allocation on SPS and the NSP System are expected to be less significant as they already participate in regional planning and cost allocation processes. Xcel Energy is in the process of determining the impacts of the new Order 1000 requirements related to future transmission development and ownership. Irrespective of the new rules, the utility subsidiaries are pursuing several new transmission facility projects.

ARCs — In 2009, the FERC adopted rules requiring RTOs to allow ARCs to offer demand response aggregation services to end-use customers of large utilities unless the relevant state regulatory agency prohibited the operation of ARCs. Under MISO's proposed tariff revisions, ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Minnesota. In 2010, MISO requested its compliance tariff revisions be effective in June 2010, and the MPUC, NDPSC, SDPUC, PSCW, and MPSC all issued orders prohibiting, or temporarily prohibiting, the operation of ARCs in their states.

In January 2011, the MPUC asked public utilities to explore the potential of programs with ARCs that compliment existing CIP initiatives. In September 2011, NSP-Minnesota agreed to propose a pilot program that would expand existing retail CIP services in a manner analogous to an ARC, but complementary with its existing CIP programs. NSP-Minnesota is waiting on the MPUC for further guidance prior to proceeding with the pilot program.

In December 2011, the FERC issued orders denying rehearing of the rules and approving most aspects of the MISO compliance filing. The FERC retained the rules allowing state regulatory authorities to prohibit ARCs within their state.

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there were unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for December 2000 through June 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the U.S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the U.S. Court of Appeals remanded the proceeding back to the FERC and indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The U.S. Court of Appeals denied a petition for rehearing in April 2009, and the mandate was issued. The

FERC has issued an order on establishing principles for the review proceeding and encouraging a settlement. The settlement process is in progress.

FERC Penalty Guidelines — The Energy Act required the FERC to adopt new regulations to implement various aspects of the Energy Act. Violations of FERC rules are potentially subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

In September 2010, the FERC issued a policy statement establishing guidelines to determine the financial penalties that would be applied for violations of FERC statutes, rules and orders, including violations of NERC mandatory reliability standard violations investigated by the FERC. The guidelines established a base violation level for various types of violations, plus mitigating or aggravating factor adders and multipliers, depending on the nature and severity of the violation. Under the guidelines, penalties can range between a minimal amount and $290 million. The guidelines indicate that the FERC can deviate from the guidelines in its discretion. The guidelines can apply to any investigation where the FERC Staff has not begun settlement negotiations regarding an alleged violation.

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While Xcel Energy cannot predict the ultimate impact new FERC regulations will have on its results of operations, cash flows or financial position, Xcel Energy continues to take action to comply with existing rules and to implement new FERC rules and regulations as they become effective.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement commenced a non-public investigation of the transmission service arrangements across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the FERC issued a preliminary report alleging Xcel Energy violated certain FERC policies, rules and approved tariffs that could result in material penalties under the FERC penalty guidelines. The report did not constitute a finding by the FERC. Xcel Energy disagreed with the preliminary report and demonstrated compliance with applicable standards. In November 2011, Xcel Energy and SPP filed proposed tariff revisions clarifying the transmission arrangements across the Lamar Tie Line prospectively.

In January 2012, the FERC approved a stipulation and consent agreement in which Xcel Energy did not admit any violations but agreed to pay a $2 million civil penalty. The FERC contemporaneously issued an order approving changes to the Xcel Energy OATT to allow continued network service arrangements under the tariff.

NERC Compliance Audits and Self-Reports — In 2010 and 2011, the NSP System, PSCo and SPS filed self-reports with the MRO, the WECC and the SPP, respectively, regarding potential violations of certain NERC CIPS. Based on the issues identified with CIPS compliance, the utility subsidiaries submitted a mitigation plan that provides for a comprehensive review of the utility subsidiaries' CIPS compliance programs. Following this comprehensive review, additional self-reports of potential violations were filed.

In 2011, the NSP System was subject to a comprehensive triennial audit by the MRO regarding compliance with various NERC mandatory reliability standards, including CIPS. The MRO found potential violations of seven standards; five are related to CIPS. The written MRO audit reports have been issued and referred to MRO's enforcement function for further action. None of the potential violations are expected to result in a material penalty.

In May 2011, PSCo was subject to a comprehensive triennial audit by the WECC regarding compliance with various NERC mandatory reliability standards. In December 2011, PSCo and WECC agreed to a settlement in principle of five violations of four NERC reliability standards, including the two violations self-reported prior to the May 2011 audit. The violations were all self-identified and self-reported to WECC. PSCo agreed to pay an immaterial penalty to resolve all five reliability standard violations. Following execution of the settlement agreement, the agreement must be approved by NERC's Board of Trustees and filed with FERC for further approval.

In July 2011, SPS filed a self-report with the SPP regarding a potential violation of a NERC reliability standard. Mitigation actions associated with this self-report are complete, and the violation is not expected to result in a material penalty.

NERC Compliance Investigations — In September 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection as a result of a series of transmission line outages. In addition, service to approximately 790 MW of load was temporarily interrupted, primarily in Saskatchewan, Canada. In late 2010, NERC transferred responsibility for completing the compliance investigation to the MRO. The final outcome of the compliance investigation, and whether and to what extent penalties for alleged violations may be assessed, is unknown at this time.

In February 2010, the NERC notified NSP-Minnesota that it was commencing a non-public investigation of NSP-Minnesota maintenance practices associated with insulating oil levels in bulk electric system substations, as the result of an anonymous complaint received by the NERC. In February 2011, NERC transferred responsibility for completing the compliance investigation to the MRO. The MRO reviewed the status of insulating oil levels during the triennial compliance audit in the first quarter 2011. In July 2011, the NERC issued a preliminary findings report with three potential violations of NERC reliability standards, which NSP-Minnesota responded to in September 2011. The final outcome of the compliance investigation and whether and to what extent penalties for alleged violations may be assessed is unknown at this time.

NERC Advisory Regarding Impact of Transmission Field Conditions on Facility Ratings — In 2010, the NERC issued an advisory requiring utilities to perform an assessment of field versus assumed "as built" transmission infrastructure conditions and allowed for affected entities to complete their initial assessment and corrective actions by 2013 and 2014, respectively. The advisory compliance cost for the utility subsidiaries is estimated at $25 million to $30 million. Xcel Energy will seek recovery through applicable rate-making mechanisms.

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Electric Transmission Rate Regulation — The FERC regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control of their electric transmission assets for the sale of electric transmission services to an RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO RTO. SPS is a member of the SPP RTO. Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates. In 2009, PSCo filed a tariff to participate with other utilities in WestConnect, a consortium of utilities offering regionalized non-firm transmission services. The WestConnect tariff was effective in the first quarter of 2009 and the FERC approved a two year extension in the second quarter of 2011. The WestConnect tariff has not had a material impact on PSCo transmission usage or revenues. WestConnect may provide wholesale energy market functions in the future, but would not be an RTO.

MISO Transmission Pricing — Certain new higher voltage transmission facilities determined by MISO to meet RECB eligibility criteria in the MISO tariff are subject to an allocation of 20 percent of the facility costs to all loads in the 15 state MISO region. Under specific FERC orders, certain new high voltage transmission facilities determined by MISO to meet MVP eligibility criteria are subject to an allocation of 100 percent of the facility costs to all loads on the MISO region. The MISO independent board of directors must approve MVP eligibility before the costs of a specific project are eligible for regional rate recovery under the MISO tariff. Certain parties have appealed the FERC MVP tariff orders to the Seventh Circuit Court of Appeals.

The MISO regional cost allocation methods require other customers in MISO to contribute to cost recovery for certain new transmission facilities constructed by the NSP System. MISO approved the eligibility of the CapX2020 Fargo, N.D. and La Crosse, Wis. transmission expansion projects for 20 percent regional allocation. In addition, in December 2011, the Brookings, S.D. CapX2020 transmission line was approved by MISO as an MVP, and thus eligible for 100 percent regional cost allocation. The CapX2020 Bemidji, Minn. transmission expansion project is not eligible for regional cost allocation. However, the NSP System also pays a share of the costs of projects constructed by other transmission-owning entities in the MISO region found to be eligible for regional cost allocation. The transmission revenues received by the NSP System from MISO, and the transmission charges paid to MISO, associated with projects subject to regional cost allocation are expected to be material in future periods. The RECB and MVP cost allocation processes may be subject to future change to comply with FERC Order 1000.

MISO Wholesale Capacity Markets — In July 2011, MISO filed to implement a resource adequacy tariff to be effective Oct. 1, 2012. The tariff would establish a MISO capacity market, which would allow the NSP System to purchase or sell short-term capacity in order to comply with regional reliability planning reserve requirements. The MISO tariff proposal would allow utility capacity arrangements determined through state resource planning processes to be deemed compliant with the tariff. The tariff proposal is pending FERC action.

Market-Based Rate Rules — Each of the Xcel Energy Inc. utility subsidiaries was granted market-based rate authority. Under market-based rates, the NSP System was reauthorized to sell wholesale power at market-based rates in June 2009. In December 2011, the NSP System filed for continued market-based rate authority, as required by FERC's triennial market power review rules effective Jan. 1, 2012. The request is pending FERC action. SPS was reauthorized to sell at market-based rate rules outside its service territory by the FERC in 2010. PSCo was reauthorized to sell at market-based rates outside its service territory in 2011. Presently, Xcel Energy Inc.'s utility subsidiaries may not sell power at market-based rates within the PSCo and SPS balancing authorities, where they have been found to have market power under the FERC's applicable analysis. Both PSCo and SPS have cost-based coordination tariffs that they may use to make sales in their balancing authorities.

RSG Charges — The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive no less than its offer price for start-up, no-load and incremental energy. In August 2010, the FERC issued two orders relating to RSG charge exemptions and the allocation of the RSG costs among MISO participants. MISO has since issued multiple related compliance filings with the FERC. In recent RSG filings, MISO has proposed to allocate a greater portion of the RSG costs related to resources committed for voltage and local reliability requirements to the market participants with the loads that benefit from such commitments. MISO has also proposed to mitigate the offers of resources committed for voltage regulation and local reliability requirements, which is expected to reduce RSG charges to other market participants under the current tariff. NSP-Minnesota is permitted to recover the RSG costs through FCA mechanisms approved by the regulators in each jurisdiction.

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Electric Operating Statistics

Electric Sales Statistics

	Year Ended Dec. 31		
	2011	2010	2009
Electric sales (Millions of KWh)			
Residential	25,278	25,143	24,039
Large commercial and industrial	27,419	27,167	26,647
Small commercial and industrial	35,597	35,650	34,608
Public authorities and other	1,135	1,100	1,079
Total retail	89,429	89,060	86,373
Sales for resale	20,177	20,532	21,588
Total energy sold	109,606	109,592	107,961
Number of customers at end of period			
Residential	2,919,660	2,906,248	2,905,105
Large commercial and industrial	1,129	1,112	1,100
Small commercial and industrial	415,755	413,750	414,603
Public authorities and other	69,350	70,413	71,677
Total retail	3,405,894	3,391,523	3,392,485
Wholesale	78	88	101
Total customers	3,405,972	3,391,611	3,392,586
Electric revenues (Thousands of Dollars)			
Residential	$2,712,340	$2,622,284	$2,355,138
Large commercial and industrial	1,616,596	1,533,993	1,422,353
Small commercial and industrial	3,025,416	2,956,077	2,649,354
Public authorities and other	129,826	126,345	116,933
Total retail	7,484,178	7,238,699	6,543,778
Wholesale	936,875	960,505	886,417
Other electric revenues	345,540	252,641	274,528
Total electric revenues	$8,766,593	$8,451,845	$7,704,723
KWh sales per retail customer	26,257	26,260	25,460
Revenue per retail customer	$2,197	$2,134	$1,929
Residential revenue per KWh	10.73 ¢	10.43 ¢	9.80 ¢
Large commercial and industrial revenue per KWh	5.90	5.65	5.34
Small commercial and industrial revenue per KWh	8.50	8.29	7.66
Wholesale revenue per KWh	4.64	4.68	4.11

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Energy Source Statistics

	Year Ended Dec. 31					
	2011		2010		2009	
	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation	Millions of KWh	Percent of Generation
Coal	57,014	50 %	57,832	51 %	56,282	50 %
Natural Gas	25,080	22	25,947	23	27,175	24
Nuclear	13,781	12	15,012	13	13,670	12
Wind (a)	11,216	10	9,885	9	9,114	8
Hydroelectric	4,203	4	3,998	3	5,167	5
Other (b)	1,659	2	1,663	1	1,464	1
Total	112,953	100 %	114,337	100 %	112,872	100 %
Owned generation	74,722	66 %	77,506	68 %	71,474	63 %
Purchased generation	38,231	34	36,831	32	41,398	37
Total	112,953	100 %	114,337	100 %	112,872	100 %

(a) This category includes wind energy de-bundled from RECs and also includes Windsource RECs. Xcel Energy uses RECs to meet or exceed state resource requirements and may sell surplus RECs.
(b) Includes energy from other sources, including solar, biomass, oil and waste. Distributed generation from the Solar*Rewards program is not included.

NATURAL GAS UTILITY OPERATIONS

Overview

The most significant developments in the natural gas operations of the utility subsidiaries are continued volatility in natural gas market prices, uncertainty regarding political and regulatory developments that impact hydraulic fracturing, safety requirements for natural gas pipelines and the continued trend of declining use per residential and small commercial and industrial (C&I) customer, as a result of improved building construction technologies, higher appliance efficiencies and conservation. From 2000 to 2011, average annual sales to the typical residential customer declined from 96 MMBtu per year to 80 MMBtu per year and to the typical small C&I customer declined from 441 MMBtu per year to 377 MMBtu per year, on a weather-normalized basis. Although wholesale price increases do not directly affect earnings because of natural gas cost-recovery mechanisms, high prices can encourage further efficiency efforts by customers.

Recent Regulatory Development

Pipeline Safety Act — The Pipeline Safety, Regulatory Certainty, and Job Creation Act, signed into law on Jan. 3, 2012 (“Pipeline Safety Act”) requires, among other things, additional verification of pipeline infrastructure records by intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) will require operators to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. In addition, the Pipeline Safety Act requires PHMSA to issue reports and/or, if appropriate, develop new regulations, addressing a variety of subjects, including: requiring use of automatic or remote-controlled shut-off valves in certain circumstances; requiring testing of previously untested transmission lines located within high consequence areas operating at a pressure greater than 30 percent of specified minimum yield stress; and expanding integrity management requirements beyond high consequence areas. The Pipeline Safety Act also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2 million for a related series of violations. While Xcel Energy cannot predict the ultimate impact Pipeline Safety Act will have on its costs, operations or financial results, Xcel Energy is taking actions that are intended to comply with the Pipeline Safety Act and any related PHMSA regulations as they become effective.

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NSP-Minnesota

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — Retail rates, services and other aspects of NSP-Minnesota's retail natural gas operations are regulated by the MPUC and the NDPSC within their respective states. The MPUC has regulatory authority over security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota's natural gas supply plans for meeting customers' future energy needs. NSP-Minnesota is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Minnesota is subject to the DOT, the Minnesota Office of Pipeline Safety, the NDPSC and the SDPUC for pipeline safety compliance, including pipeline facilities used in electric utility operations for fuel deliveries.

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

Minnesota state law requires utilities to invest 0.5 percent of their state natural gas revenues in CIP. These costs are recovered through customer base rates and an annual cost-recovery mechanism for the CIP expenditures.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Minnesota was 751,985 MMBtu, which occurred on Jan. 20, 2011 and 689,223 MMBtu, which occurred on Dec. 13, 2010.

NSP-Minnesota purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of 587,811 MMBtu per day. In addition, NSP-Minnesota contracts with providers of underground natural gas storage services. These agreements provide storage for approximately 26 percent of winter natural gas requirements and 32 percent of peak day firm requirements of NSP-Minnesota.

NSP-Minnesota also owns and operates one LNG plant with a storage capacity of 2.0 Bcf equivalent and three propane-air plants with a storage capacity of 1.3 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 31 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days.

NSP-Minnesota is required to file for a change in natural gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or to exchange one form of demand for another. The 2009-2010, 2010-2011, and 2011-2012 entitlement levels are pending MPUC action.

Natural Gas Supply and Costs

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

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

2011	$5.25
2010	5.43
2009	5.78

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

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NSP-Minnesota has firm natural gas transportation contracts with several pipelines, which expire in various years from 2012 through 2027.

NSP-Minnesota has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2011, NSP-Minnesota was committed to approximately $394 million in such obligations under these contracts.

NSP-Minnesota purchases firm natural gas supply utilizing long-term and short-term agreements from approximately 32 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Minnesota to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

NSP-Wisconsin

Public Utility Regulation

Summary of Regulatory Agencies and Areas of Jurisdiction — NSP-Wisconsin is regulated by the PSCW and the MPSC. The PSCW has a biennial base-rate filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the test year period beginning the following January. NSP-Wisconsin is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce. NSP-Wisconsin is subject to the DOT, the PSCW and the MPSC for pipeline safety compliance.

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

NSP-Wisconsin’s natural gas rate schedules for Michigan customers include a natural gas cost-recovery factor, which is based on 12-month projections.

Capability and Demand

Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). The maximum daily send-out (firm and interruptible) for NSP-Wisconsin was 134,636 MMBtu, which occurred on Jan. 20, 2011, and 146,018 MMBtu, which occurred on Dec. 14, 2010.

NSP-Wisconsin purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 133,110 MMBtu per day. In addition, NSP-Wisconsin contracts with providers of underground natural gas storage services. These storage agreements provide storage for approximately 27 percent of winter natural gas requirements and 39 percent of peak day firm requirements of NSP-Wisconsin.

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

NSP-Wisconsin is required to file a natural gas supply plan with the PSCW annually to change natural gas supply contract levels to meet peak demand. NSP-Wisconsin's winter 2011-2012 supply plan was approved by the PSCW in November 2011.

Natural Gas Supply and Costs

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

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

2011	$5.18
2010	5.46
2009	5.85

The cost of natural gas supply, transportation service and storage service is recovered through various cost-recovery adjustment mechanisms. NSP-Wisconsin has firm natural gas transportation contracts with several pipelines, which expire in various years from 2012 through 2029.

NSP-Wisconsin has certain natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2011, NSP-Wisconsin was committed to approximately $94 million in such obligations under these contracts.

NSP-Wisconsin purchased firm natural gas supply utilizing long-term and short-term agreements from approximately 14 domestic and Canadian suppliers. This diversity of suppliers and contract lengths allows NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

See Items 1A and 7 for further discussion of natural gas supply and costs.

PSCo

Public Utility Regulation

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

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

- GCA — The GCA recovers the actual costs of purchased gas and transportation to meet the requirements of its customers and is revised quarterly to allow for changes in gas rates. Effective September 2011, the GCA recovers the return on gas in underground storage.
- DSMCA — PSCo has a low-income energy assistance program. The costs of this energy conservation and weatherization program are recovered through the gas DSMCA.
- PSIA — Effective Jan. 1, 2012, the PSIA began to recover costs associated with transmission and distribution pipeline integrity management programs and two projects to replace large transmission pipelines.

QSP Requirements — The CPUC established a natural gas QSP. This regulatory plan includes a natural gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to natural gas leak repair time and customer service through 2012. The CPUC conducts proceedings to review and approve the rate adjustment annually.

Capability and Demand

PSCo projects peak day natural gas supply requirements for firm sales and backup transportation, which include transportation customers contracting for firm supply backup, to be 1,926,635 MMBtu. In addition, firm transportation customers hold 565,008 MMBtu of capacity for PSCo without supply backup. Total firm delivery obligation for PSCo is 2,491,643 MMBtu per day. The maximum daily deliveries for PSCo for firm and interruptible services were 2,155,547 MMBtu on Feb. 1, 2011 and 1,820,806 on Jan. 7, 2010.

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PSCo purchases natural gas from independent suppliers, generally based on market indices that reflect current prices. The natural gas is delivered under transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 1,847,668 MMBtu per day, which includes 853,453 MMBtu of natural gas held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide about 22,400 MMBtu of natural gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at PSCo's city gate meter stations and a small amount is received directly from wellhead sources.

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

Natural Gas Supply and Costs

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

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

2011	$4.99
2010	5.10
2009	5.13

PSCo has natural gas supply, transportation and storage agreements that include obligations for the purchase and/or delivery of specified volumes of natural gas or to make payments in lieu of delivery. At Dec. 31, 2011, PSCo was committed to approximately $1.1 billion in such obligations under these contracts, which expire in various years from 2012 through 2029.

PSCo purchases natural gas by optimizing a balance of long-term and short-term natural gas purchases, firm transportation and natural gas storage contracts. During 2011, PSCo purchased natural gas from approximately 41 suppliers.

See Items 1A and 7 for further discussion of natural gas supply and costs.

SPS

Natural Gas Facilities Used for Electric Generation

SPS does not provide natural gas service at retail, but purchases and transports natural gas for certain of its generation facilities and operates natural gas pipeline facilities connecting the generation facilities to interstate natural gas pipelines. SPS is subject to the jurisdiction of the FERC with respect to certain natural gas transactions in interstate commerce; and to the jurisdiction of the DOT and the PUCT for pipeline safety compliance.

See Items 1A and 7 for further discussion of natural gas costs.

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Natural Gas Operating Statistics

	Year Ended Dec. 31		
	2011	2010	2009
Natural gas deliveries (Thousands of MMBtu)			
Residential	139,200	137,809	141,719
Commercial and industrial	86,788	87,599	88,943
Total retail	225,988	225,408	230,662
Transportation and other	117,654	121,261	126,993
Total deliveries	343,642	346,669	357,655
Number of customers at end of period			
Residential	1,747,153	1,735,032	1,723,419
Commercial and industrial	153,911	152,937	152,312
Total retail	1,901,064	1,887,969	1,875,731
Transportation and other	5,395	5,281	4,826
Total customers	1,906,459	1,893,250	1,880,557
Natural gas revenues (Thousands of Dollars)			
Residential	$1,133,888	$1,115,253	$1,159,079
Commercial and industrial	601,298	589,449	631,728
Total retail	1,735,186	1,704,702	1,790,807
Transportation and other	76,740	77,880	74,896
Total natural gas revenues	$1,811,926	$1,782,582	$1,865,703
MMBtu sales per retail customer	118.87	119.39	122.97
Revenue per retail customer	$913	$903	$955
Residential revenue per MMBtu	8.15	8.09	8.18
Commercial and industrial revenue per MMBtu	6.93	6.73	7.10
Transportation and other revenue per MMBtu	0.65	0.64	0.59

ENVIRONMENTAL MATTERS

Xcel Energy’s facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Xcel Energy’s facilities have been designed and constructed to operate in compliance with applicable environmental standards. Xcel Energy strives to comply with all environmental regulations applicable to its operations. However, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, what effect future laws or regulations may have upon Xcel Energy’s operations. See Item 7 and Notes 12 and 13 to the consolidated financial statements for further discussion.

There are significant future environmental regulations under consideration to encourage the use of clean energy technologies and regulate emissions of GHGs to address climate change. While environmental regulations related to climate change and clean energy continue to evolve, Xcel Energy has undertaken a number of initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Although the impact of these policies on Xcel Energy will depend on the specifics of state and federal policies, legislation, and regulation, we believe that, based on prior state commission practice, we would be granted the authority to recover the cost of these initiatives through rates.

Xcel Energy is committed to addressing climate change and potential climate change regulation through efforts to reduce its GHG emissions in a balanced, cost-effective manner. Xcel Energy adopted a methodology for calculating CO2 emissions based on the reporting protocols of The Climate Registry, a nonprofit organization that provides and compiles GHG emissions data from reporting entities. As third-party CO2 reporting protocols continue to evolve, Xcel Energy expects additional changes in reporting methodology and reported CO2 emissions. Starting in 2011, Xcel Energy began reporting GHG emissions to the EPA. Certain REC transactions include a transfer of environmental attributes. It is not clear whether future GHG reporting regulations could require reporting of CO2 emissions for such REC transfers; current EPA reporting rules do not address REC transactions.

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Based on The Climate Registry's current reporting protocol, Xcel Energy estimated that its current electric generating portfolio, which includes coal- and gas-fired plants, emitted approximately 59.8 million and 61.7 million tons of CO_2 in 2011 and 2010, respectively. Xcel Energy also estimated emissions associated with electricity purchased for resale to Xcel Energy customers from generation facilities owned by third parties. Xcel Energy estimates that these third-party facilities emitted approximately 19.6 million and 19.5 million tons of CO_2 in 2011 and 2010, respectively. Estimated total CO_2 emissions, associated with service to Xcel Energy electric customers, decreased by 1.8 million tons in 2011 compared to 2010. The decrease in emissions was associated with a decrease of 1.4 million MWh of generation. The average annual decrease in CO_2 emissions since 2009 is approximately 3.0 million tons of CO_2 per year.

CAPITAL SPENDING AND FINANCING

See Item 7 for a discussion of expected capital expenditures and funding sources.

EMPLOYEES

As of Dec. 31, 2011, Xcel Energy had 11,312 full-time employees, 5,592 of which are covered under collective bargaining agreements. See Note 9 to the consolidated financial statements for further discussion.

EXECUTIVE OFFICERS

Benjamin G.S. Fowke III, 53, Chairman of the Board, President and Chief Executive Officer, Xcel Energy Inc., August 2011 to present. Previously, President and Chief Operating Officer, Xcel Energy Inc., August 2009 to August 2011; Executive Vice President and Chief Financial Officer, Xcel Energy Inc., December 2008 to August 2009; Vice President and Chief Financial Officer, Xcel Energy Inc., May 2004 to December 2008; Vice President, Chief Financial Officer and Treasurer, Xcel Energy Inc., October 2003 to May 2004; Vice President and Treasurer, Xcel Energy Inc., November 2002 to October 2003; and Vice President and Chief Financial Officer, Energy Markets Business Unit, Xcel Energy Services Inc., August 2000 to November 2002.

Michael C. Connelly, 50, Senior Vice President, Strategy and Planning, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President and General Counsel, Xcel Energy Inc., June 2007 to September 2011; Vice President of Human Resources, Xcel Energy Services Inc., November 2005 to June 2007; Vice President and Deputy General Counsel, Xcel Energy Services Inc., January 2003 to November 2005; and Deputy General Counsel, Xcel Energy Services Inc., August 2000 to January 2003.

David L. Eves, 53, President, Director and Chief Executive Officer, PSCo, December 2009 to present. Previously, President, Director and Chief Operating Officer, PSCo, November 2009 to December 2009; President and Director, SPS, December 2006 to November 2009; Chief Executive Officer, SPS, August 2006 to November 2009; Vice President of Resource Planning and Acquisition, Xcel Energy Services Inc., November 2002 to July 2006; and Managing Director, Resource Planning and Acquisition, Xcel Energy Services Inc., August 2000 to November 2002.

Cathy J. Hart, 62, Vice President and Corporate Secretary, Xcel Energy Inc., August 2000 to present and Vice President, Business Services Group, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President, Corporate Services Group, Xcel Energy Services Inc., November 2005 to September 2011.

C. Riley Hill, 52, President, Director and Chief Executive Officer, SPS, November 2009 to present. Previously, Vice President and Chief Operating Officer, SPS, July 2009 to November 2009; Regional Vice President, Xcel Energy Services Inc., November 2007 to July 2009; Vice President, Construction, Operations and Maintenance, PSCo, February 2006 to November 2007; and Director Design and Construction, PSCo, March 2004 to February 2006.

Dennis L. Koehl, 56, Senior Vice President and Chief Nuclear Officer, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President and Chief Nuclear Officer, NSP-Minnesota, September 2007 to September 2011; Site Vice President, NMC Point Beach Nuclear Plant, June 2004 to September 2007; Engineering and Site Support Manager, Tennessee Valley Authority, Sequoyah Nuclear Plant, August 2003 to June 2004; and Plant Manager, Tennessee Valley Authority, Sequoyah Nuclear Plant, January 1999 to August 2003.

Kent T. Larson, 52, Senior Vice President, Operations, Xcel Energy Services Inc., September 2011 to present. Previously, Chief Energy Supply Officer, Xcel Energy Services Inc., March 2010 to September 2011; Vice President, Transmission, Xcel Energy Services Inc., August 2008 to March 2010; Regional Vice President, Xcel Energy Services Inc., February 2006 to August 2008; Vice President, Jurisdictional Relations, Xcel Energy Services Inc., April 2004 to February 2006; and State Vice President, NSP-Minnesota, September 2000 to April 2004.

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Teresa S. Madden, 55, Senior Vice President and Chief Financial Officer, Xcel Energy Inc., September 2011 to present. Previously, Vice President and Controller, Xcel Energy Inc., January 2004 to September 2011; Vice President of Finance, Customer and Field Operations Business Unit, Xcel Energy Inc., August 2003 to January 2004; Interim Chief Financial Officer, Rogue Wave Software, Inc., February 2003 to July 2003; and Corporate Controller, Rogue Wave Software, Inc., October 2000 to February 2003.

Marvin E. McDaniel, Jr., 51, Senior Vice President and Chief Administrative Officer, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President and Chief Administrative Officer, Xcel Energy Services Inc., August, 2009 to September 2011 and Vice President, Talent and Technology Business Areas, Xcel Energy Inc., August 2009 to September 2011; Vice President, Human Resources, July 2007 to August 2009; Vice President and Assistant Controller, March 2005 to June 2007, Xcel Energy Services Inc.; and Vice President and Controller Energy Markets Business Unit, Xcel Energy Services Inc., February 2004 to February 2005.

R. Roy Palmer, 53, Senior Vice President, Public Policy and External Affairs, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President, Federal and State Government Affairs, Xcel Energy Services Inc., January 2009 to September 2011; Managing Director, Government and Regulatory Affairs, Xcel Energy Services, Inc., November 2007 to January 2009; Executive Director, State Public Affairs, Xcel Energy Services Inc., April 2005 to November 2007; and Director, Regional Government Affairs, Xcel Energy Services Inc., March 2004 to April 2005.

Judy M. Poferl, 51, President, Director and Chief Executive Officer, NSP-Minnesota, August 2009 to present. Previously, Regional Vice President, NSP-Minnesota, September 2008 to August 2009; Managing Director, Government and Regulatory Affairs, Xcel Energy Services Inc., November 2007 to September 2008; and Director, Regulatory Administration, Xcel Energy Services Inc., August 2000 to November 2007.

Jeffrey S. Savage, 40, Vice President and Controller, Xcel Energy Inc., September 2011 to present. Previously, Senior Director, Financial Reporting, Corporate and Technical Accounting, Xcel Energy Services Inc., December 2009 to September 2011; Director, Financial Reporting and Technical Accounting, Xcel Energy Services Inc., March 2007 to December 2009; and Director, Financial Reporting and Technical Accounting, The Mosaic Company, January 2006 to March 2007.

David M. Sparby, 57, Senior Vice President and Group President, Xcel Energy Services Inc., September 2011 to present. Previously, Vice President and Chief Financial Officer, Xcel Energy Inc., August 2009 to September 2011; President, Director and Chief Executive Officer, NSP-Minnesota, August 2008 to August 2009; Executive Vice President and Director, Acting President and Chief Executive Officer, NSP-Minnesota, January 2007 to August 2008; and Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., September 2000 to January 2007.

Mark E. Stoering, 51, President, Director and Chief Executive Officer, NSP-Wisconsin, January 2012 to present. Previously, Vice President, Portfolio Strategy and Business Development, Xcel Energy Services Inc., August 2000 to December 2011.

George E. Tyson, II, 46, Vice President and Treasurer, Xcel Energy Inc., May 2004 to present. Previously, Managing Director and Assistant Treasurer, Xcel Energy Inc., July 2003 to May 2004; Director of Origination, Energy Markets Business Unit, Xcel Energy Services Inc., May 2002 to July 2003; and Associate and Vice President, Deutsche Bank Securities, December 1996 to April 2002.

Scott M. Wilensky, 55, Senior Vice President and General Counsel, Xcel Energy Inc., September 2011 to present. Previously, Vice President, Regulatory and Resource Planning, Xcel Energy Services Inc., September 2009 to September 2011; Vice President, Government and Regulatory Affairs, Xcel Energy Services Inc., August 2008 to

September 2009; Executive Director, Revenue, Xcel Energy Services Inc., March 2006 to August 2008; Director, State Public Affairs, Xcel Energy Services Inc., November 2001 to March 2006; Assistant General Counsel, Xcel Energy Services Inc., August 2001 to November 2001; and Senior Attorney, Xcel Energy Services Inc., December 1998 to August 2001.

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

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Item 1A — Risk Factors

Oversight of Risk and Related Processes

The goal of Xcel Energy's risk management process is to understand, manage and, when possible, mitigate material risk. Xcel Energy management is responsible for identifying and managing risks, while the Board of Directors oversees and holds management accountable. As described more fully below, Xcel Energy is faced with a number of different types of risk. Xcel Energy confronts legislative and regulatory policy and compliance risks, including risks related to climate change and emission of CO2; risks for recovery of capital and operating costs; resource planning and other long-term planning risks, including resource acquisition risks; financial risks, including credit, interest rate and capital market risks; and macroeconomic risks, including risks related to economic conditions and changes in demand for Xcel Energy's products and services. Cross-cutting risks such as these are discussed and managed across business areas and coordinated by Xcel Energy's senior management. Our risk management process has three parts: identification and analysis, management and mitigation and communication and disclosure.

Xcel Energy management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Management broadly considers our business, the utility industry, the domestic and global economy and the environment to identify risks. Identification and analysis occurs formally through a key risk assessment process conducted by senior management, the securities disclosure process, the hazard risk management process and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through its business planning process and development of goals and key performance indicators, which include risk identification to determine barriers to implementing Xcel Energy's strategy. At the same time, the business planning process identifies areas in which there is a potential for a business area to take inappropriate risk to meet goals and determines how to prevent inappropriate risk-taking.

Xcel Energy management seeks to mitigate the risks inherent in the implementation of Xcel Energy's strategy. The process for risk mitigation includes adherence to our code of conduct and other compliance policies, operation of formal risk management structures and groups, and overall business management. At a threshold level, Xcel Energy has developed a robust compliance program and promotes a culture of compliance, which further mitigates risk. Building on this culture of compliance, Xcel Energy manages and mitigates risks through operation of formal risk management structures and groups, including management councils, risk committees and the services of corporate areas such as internal audit, the corporate controller and legal services. While Xcel Energy has developed a number of formal structures for risk management, many material risks affect the business as a whole and are managed across business areas.

Xcel Energy management also communicates with the Board and key stakeholders regarding risk. Xcel Energy provides information to the Board in presentations and communications over the course of the year. Senior management presents an assessment of key risks to the Board annually. The presentation of the key risks and the discussion provides the Board with information on the risks management believes are material, including the earnings impact, timing, likelihood and controllability. Based on this presentation, the Board reviews risks at an enterprise level and confirms risk management and mitigation are included in Xcel Energy's strategy. The guidelines on corporate governance and committee charters define the scope of review and inquiry for the Board and committees. The standing committees also oversee risk management as part of their charters. Each committee has responsibility for overseeing aspects of risk and Xcel Energy's management and mitigation of the risk. The Board has overall responsibility for risk oversight. As described above, the Board reviews the key risk assessment process presented by senior management. This key risk assessment analyzes the most likely areas of future risk to Xcel Energy. The Board also reviews the performance and annual goals of each business area. This review, when combined with the oversight of specific risks by the committees, allows the Board to confirm risk is considered in the development of goals and that risk has been adequately considered and mitigated in the execution of corporate strategy. The presentation of the assessment of key risks also provides the basis for the discussion of risk in our public filings and securities disclosures.

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Risks Associated with Our Business

Environmental Risks

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

We are subject to environmental laws and regulations that affect many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. These laws and regulations require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to restrict or limit the output of certain facilities or the use of certain fuels, to install pollution control equipment at our facilities, clean up spills and correct environmental hazards and other contamination. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We may be required to pay all or a portion of the cost to remediate (i.e., clean-up) sites where our past activities, or the activities of certain other parties, caused environmental contamination. At Dec. 31, 2011, these sites included:

- Sites of former MGPs operated by our subsidiaries, predecessors, or other entities; and
- Third party sites, such as landfills, for which we are alleged to be a PRP that sent hazardous materials and wastes.

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

In addition, existing environmental laws or regulations may be revised, and new laws or regulations seeking to protect the environment may be adopted or become applicable to us, including but not limited to, regulation of mercury, NOx, SO2, CO2, particulates and coal ash. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations.

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

There is a growing consensus that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. We do not serve any coastal communities so the possibility of sea level rises does not directly affect us or our customers.

Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

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

Financial Risks

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

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

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

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

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

We cannot be assured that any of our current ratings or our subsidiaries' ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. For example, Standard & Poor's calculates an imputed debt associated with capacity payments from purchased power contracts. An increase in the overall level of capacity payments would increase the amount of imputed debt, based on Standard & Poor's methodology. Therefore, Xcel Energy Inc. and its subsidiaries credit ratings could be adversely affected based on the level of capacity payments associated with purchased power contracts or changes in how imputed debt is determined. Any downgrade could lead to higher borrowing costs. Also, our utility subsidiaries may enter into certain procurement and derivative contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below investment grade.

We are subject to capital market and interest rate risks.

Utility operations require significant capital investment in property, plant and equipment; consequently, we are an active participant in debt and equity markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital markets are global in nature and are impacted by numerous issues and events throughout the world economy, such as the recent concerns regarding European sovereign debt. Capital market disruption events, and resulting broad financial market distress, such as the events surrounding the collapse in the U.S. sub-prime mortgage market, could prevent us from issuing new securities or cause us to issue securities with less than ideal terms and conditions, such as higher interest rates.

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Higher interest rates on short-term borrowings with variable interest rates or on incremental commercial paper issuances could also have an adverse effect on our operating results. Changes in interest rates may also impact the fair value of the debt securities in the nuclear decommissioning fund and master pension trust, as well as our ability to earn a return on short-term investments of excess cash.

We are subject to credit risks.

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

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

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which create an additional need for liquidity to post margin as exchange positions change value daily. The Dodd-Frank Wall Street Reform Act may require broad clearing of financial swap transactions through a central counterparty, which could lead to additional margin requirements that would impact our liquidity. Also, in October 2010, the FERC finalized its Order 741 rulemaking addressing the credit policies of organized electric markets, such as MISO and SPP. FERC Order 741 limits the amount of overall credit available to entities operating within organized markets and places restrictions on netting of transactions within organized markets unless certain market protocols are implemented by the RTO. Various RTOs are in the process of filing their proposed market protocols to satisfy FERC Order 741 and these new market designs may lead to additional margin requirements that could impact our liquidity.

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

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

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

We have defined benefit pension and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock and bond market performance, changes in interest rates and changes in governmental regulations. In addition, the Pension Protection Act of 2006 changed the minimum funding requirements for defined benefit pension plans beginning in 2008. Therefore, our funding requirements and related contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid.

Increasing costs associated with health care plans may adversely affect our results of operations.

Our self-insured costs of health care benefits for eligible employees and costs for retiree health care plans have increased substantially in recent years. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our operating results, financial position, and liquidity. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. Legislation related to health care could also significantly change our benefit programs and costs.

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

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

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

Operational Risks

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

We engage in wholesale sales and purchases of electric capacity, energy and energy-related products and are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis (mark-to-market accounting), which may cause earnings volatility. Actual settlements can vary significantly from these estimates, and significant changes from the assumptions underlying our fair value estimates could cause significant earnings variability.

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

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

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

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

The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or a substantial increase in operating expenses at NSP-Minnesota's nuclear plants. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

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If an incident did occur, it could have a material effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities. The events at the nuclear plant in Fukushima, Japan could result in increased regulation of the nuclear generation industry as a whole, and additional requirements with respect to emergency planning and demonstrated ability to operate nuclear facilities in the event of natural disasters or other events. This increased regulation could increase NSP-Minnesota's compliance costs and impact the results of operations of its nuclear facilities. Furthermore, these events could cause increased regulatory review and scrutiny by the NRC which could lead to delays in the process for obtaining required regulatory reviews and approvals.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota's production and transmission system, and NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

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

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

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

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

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

Additionally, the cost of potential regulations related to pipeline safety could be significant.

Public Policy Risks

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

Increased public awareness and concern regarding climate change may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHGs, and federal legislation has been introduced in both houses of Congress. In 2009, the U.S. submitted a non-binding GHG emission reduction target of 17 percent compared to 2005 levels pursuant to the

Copenhagen Accord and negotiations continue under the United Nations Framework Convention on Climate Change. Such legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities are likely to be subject to regulation under climate change laws introduced at either the state or federal level within the next few years.

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The EPA has taken steps to regulate GHGs under the CAA. In December 2009, the EPA issued a finding that GHG emissions endanger public health and welfare, and that motor vehicle emissions contribute to the GHGs in the atmosphere. This endangerment finding created a mandatory duty for the EPA to regulate GHGs from light duty motor vehicles. In January 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which are applicable to construction of new power plants or power plant modifications that increase emissions above a certain threshold. The EPA has also announced that it will propose GHG regulations applicable to emissions from existing power plants, although the EPA announced in late September 2011 that this proposed rule will be delayed.

We are also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in Note 13 to the consolidated financial statements. An adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

There are many uncertainties regarding when and in what form climate change legislation or regulations will be enacted. The impact of legislation and regulations, on us and our customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are recognized as compliance options, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the U.S., any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include, but are not limited to, rules associated with emissions of SO2 and NOx, mercury, regional haze, ozone, ash management and cooling water intake systems. The costs of investment to comply with these rules could be substantial. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Increased risks of regulatory penalties could negatively impact our business.

The Energy Act increased the FERC’s civil penalty authority for violation of FERC statutes, rules and orders. The FERC can now impose penalties of $1 million per violation per day. In addition, electric reliability standards that were historically subject to voluntary compliance are now mandatory and subject to potential financial penalties by regional entities, the NERC or the FERC for violations. If a serious reliability incident did occur, it could have a material effect on our operations or financial results.

Macroeconomic Risks

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged economic recession and uncertainty of recovery may result in a sustained lower level of economic activity and uncertainty with respect to energy prices and the capital and commodity markets. A sustained lower level of economic activity may also result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital, which are discussed in greater detail in the capital market risk section above.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers' ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt.

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

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

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

The insurance industry has also been affected by these events and the availability of insurance covering risks we and our competitors typically insure against may decrease. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. For example, wildfire events, particularly in the geographic areas we serve, may cause insurance for wildfire losses to become difficult or expensive to obtain.

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

The degree to which we are able to maintain day-to-day operations in response to unforeseen events, potentially through the execution of our business continuity plans, will in part determine the financial impact of certain events on our financial condition and results. It’s difficult to predict the magnitude of such events and associated impacts.

A cyber incident or cyber security breach could have a material effect on our business.

Our generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets could be directly or indirectly affected by unintentional or deliberate cyber incidents. Cyber intrusion or other similar events could harm our businesses by limiting our generating, transmitting and distributing capabilities or delay our development and construction of new facilities or capital improvement projects to existing facilities. In addition, as generation and transmission systems as well as natural gas pipelines are part of an interconnected system, a disruption caused by the impact of a cyber security event of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources could also negatively impact our business. We are unable to quantify the potential impact of such cyber security threats. These events and corresponding regulatory action, if any, could result in a material decrease in revenues and may cause significant additional costs (e.g., repairs/insurance) and potentially disrupt our supply and markets for natural gas, oil and other fuels.

We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite our control environment and security measures, our technology systems may be vulnerable to disability, failures or unauthorized access due to cyber intrusion. If our technology systems were to fail or be breached, or those of our third-party service providers, we may be unable to fulfill critical business functions, including effectively maintaining certain internal controls over financial reporting. In addition, confidential and other data, including sensitive customer or employee information, could be compromised exposing us to liability and business disruption.

Rising energy prices could negatively impact our business.

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

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

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

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

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

Electric Utility Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	Summer 2011 Net Dependable Capability (MW)	
Steam:				
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511	
Sherco-Becker, Minn.				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	507	(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	554	
Prairie Island-Welch, Minn.				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Black Dog-Burnsville, Minn., 2 Units	Coal/Natural Gas	1955-1960	232	
Various locations, 4 Units	Wood/Refuse-derived fuel	Various	36	(b)
Combustion Turbine:				
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	338	
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	236	
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	462	
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	486	
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470	
Various locations, 18 Units	Natural Gas	Various	107	
Wind:				
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101	(c)

Nobles-Nobles County, Minn., 134 Units	Wind	2010	201(c)
		Total	6,925

(a) Based on NSP-Minnesota's ownership of 59 percent. In November 2011, Sherco Unit 3, jointly owned by NSP-Minnesota and Southern Minnesota Municipal Power Agency, experienced a significant failure of its turbine, generator and exciter systems. See Note 5 to the consolidated financial statements.
(b) Refuse-derived fuel is made from municipal solid waste.
(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

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NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2011 Net Dependable Capability (MW)
Steam:			
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	56
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	17
Combustion Turbine:			
Flambeau Station-Park Falls, Wis., 1 Unit	Natural Gas	1969	13
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	122
Wheaton-Eau Claire, Wis., 6 Units	Natural Gas	1973	300
Hydro:			
Various locations, 63 Units	Hydro	Various	135
		Total	643

PSCo

Station, Location and Unit	Fuel	Installed	Summer 2011 Net Dependable Capability (MW)	
Steam:				
Arapahoe-Denver, Colo., 2 Units	Coal	1951-1955	153	
Cherokee-Denver, Colo., 3 Units	Coal	1957-1968	611	(a)
Comanche-Pueblo, Colo.				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	511	(b)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83	(c)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	237	(d)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505	
Valmont-Boulder, Colo., 1 Unit	Coal	1964	184	
Zuni-Denver, Colo., 1 Unit	Coal	1948-1954	65	
Combustion Turbine:				
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264	
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969	
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	173	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
Wind:				
Ponnequin-Weld County, Colo., 37 Units	Wind	1999-2001	25	(e)
		Total	5,256	

(a) Cherokee Unit 2 was taken out of service in October 2011.

(b) Based on PSCo’s ownership interest of 67 percent of Unit 3.

(c) Based on PSCo’s ownership interest of 10 percent.

(d) Based on PSCo’s ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

(e) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. The on-demand net maximum capacity is based on a company assumption of 12.5 percent dependable generation rate.

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SPS

Station, Location and Unit	Fuel	Installed	Summer 2011 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112
Moore County-Amarillo, Texas, 1 Unit	Natural Gas	1954	46
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	412
Combustion Turbine:			
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	10
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	214
Jones-Lubbock, Texas, 1 Unit	Natural Gas	2011	171 (a)
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61
Riverview-Electric City, Texas, 1 Unit	Natural Gas	1973	22
		Total	4,330

(a) Construction of Jones Unit 3 was completed in 2011.

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2011:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	-	-	-
345 KV	6,388	1,152	1,614	6,806
230 KV	1,801	-	12,177	9,705
161 KV	275	1,548	-	-
138 KV	-	-	92	-
115 KV	7,691	1,791	4,931	11,216
Less than 115 KV	82,706	31,903	73,392	21,486

Electric utility transmission and distribution substations at Dec. 31, 2011:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	372	204	224	425

Natural gas utility mains at Dec. 31, 2011:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	137	-	2,310	11
Distribution	9,688	2,231	21,414	-

Item 3 — Legal Proceedings

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

Additional Information

See Note 13 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 12 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

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Item 4 — Mine Safety Disclosures

None.

PART II

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

Quarterly Stock Data

Xcel Energy Inc.'s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The number of common shareholders of record as of Dec. 31, 2011 was approximately 76,498. The following are the reported high and low sales prices based on the NYSE Composite Transactions for the quarters of 2011 and 2010 and the dividends declared per share during those quarters.

2011	High	Low	Dividends
First quarter	$ 24.67	$ 23.17	$ 0.2525
Second quarter	25.39	23.38	0.2600
Third quarter	25.60	21.20	0.2600
Fourth quarter	27.78	23.48	0.2600

2010	High	Low	Dividends
First quarter	$ 21.76	$ 19.82	$ 0.2450
Second quarter	22.14	19.81	0.2525
Third quarter	23.28	20.47	0.2525
Fourth quarter	24.36	23.02	0.2525

Xcel Energy Inc.'s Articles of Incorporation place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. On Oct. 31, 2011, Xcel Energy Inc. redeemed all series of its preferred stock. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.'s dividend policy.

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The following compares our cumulative TSR on common stock with the cumulative total return of the EEI Investor-Owned Electrics Index and the Standard & Poor's 500 Composite Stock Price Index over the last five fiscal years (assuming a $100 investment in each vehicle on Dec. 31, 2006, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 55 companies and is a broad measure of industry performance.

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

* $100 invested on Dec. 31, 2006 in stock and index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2006	2007	2008	2009	2010	2011
Xcel Energy Inc.	$100	$102	$88	$106	$123	$150
EEI Investor-Owned Electrics	100	117	86	96	102	123
S&P 500	100	105	66	84	97	99

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

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UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the year ended Dec. 31, 2011:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
01/01/11 - 01/31/11 (a)	16,783	$ 24.00	-	-
02/01/11 - 02/28/11	-	-	-	-
03/01/11 - 03/31/11 (b)	10,625	23.75	-	-
04/01/11 - 04/30/11	-	-	-	-
05/01/11 - 05/31/11	-	-	-	-
06/01/11 - 06/30/11	-	-	-	-
07/01/11 - 07/31/11	-	-	-	-
08/01/11 - 08/31/11	-	-	-	-
09/01/11 - 09/30/11	-	-	-	-
10/01/11 - 10/31/11 (c)	1,049,800	103.11	-	-
(d)	8,500	25.84		
11/01/11 - 11/30/11	-	-	-	-
12/01/11 - 12/31/11	-	-	-	-
Total	1,085,708		-	-

(a) Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

(b) The repurchase of common shares was made pursuant to the Xcel Energy Inc. Executive Annual Incentive Award Plan. The shares were returned to Xcel Energy Inc. on behalf of some of the participants receiving an incentive award of common shares to effectuate the payment of federal and state income taxes on the award.

(c) In September 2011, Xcel Energy Inc. announced it would redeem all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends.

(d) Reflects the repurchase of common shares in the open market that Xcel Energy Inc. repurchased in connection with the exercise of stock options.

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Item 6 — Selected Financial Data

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2011	2010	2009	2008	200
Operating revenues	$10,655	$10,311	$9,644	$11,203	$10,0
Operating expenses	8,873	8,691	8,176	9,812	8,68
Income from continuing operations	841	752	686	646	576
Net income	841	756	681	646	577
Earnings available to common shareholders	834	752	677	641	573
Weighted average common shares outstanding:					
Basic	485,039	462,052	456,433	437,054	416,
Diluted	485,615	463,391	457,139	441,813	433,
Earnings per share from continuing operations:					
Basic	$1.72	$1.62	$1.49	$1.47	$1.38
Diluted	1.72	1.61	1.49	1.46	1.35
Earnings per share:					
Basic	1.72	1.63	1.48	1.47	1.38
Diluted	1.72	1.62	1.48	1.46	1.35
Dividends declared per common share	1.03	1.00	0.97	0.94	0.91
Total assets	29,497	27,388	25,306	24,805	23,0
Long-term debt (a)	8,849	9,263	7,889	7,732	6,34
Book value per share	17.44	16.76	15.92	15.35	14.7
Return on average common equity	10.1 %	9.8 %	9.5 %	9.7 %	9.5
Ratio of earnings to fixed charges (b)	2.8	2.7	2.5	2.5	2.2

(a) Includes capital lease obligations.

(b) Includes allowance for funds used during construction.

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

Business Segments and Organizational Overview

Continuing Operations

Xcel Energy Inc. is a public utility holding company. In 2011, Xcel Energy's continuing operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.

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

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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. results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; 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 Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including “Risk Factors” in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto.

Management’s Strategic Plans

Xcel Energy’s corporate strategy focuses on three core objectives:

- Obtain stakeholder alignment;
- Invest in our regulated utility businesses; and
- Earn a fair return on our utility investments.

Achievement of these strategic plans is designed to provide our investors with an attractive total return and our customers with clean, safe, reliable energy at a reasonable price. Below is a discussion of our three primary objectives and how they support our overall strategy.

Obtain stakeholder alignment

Successful execution of our strategy begins with obtaining stakeholder support for long-term decisions and for large investment initiatives, prior to taking action. To avoid excessive risk, it is critical that Xcel Energy reduce regulatory and legislative uncertainty before making long-term critical decisions or large capital investments. Stakeholder alignment is achieved by:

- Delivering operational excellence related to reliability, outage performance and customer satisfaction;
- Proactively taking actions to ensure public and employee safety related to our power plants, natural gas pipelines, and our transmission and distribution system;
- Pursuing environmental leadership by reducing emissions, and expanding renewable energy in a cost-effective manner; and

- Creating value for our customers by modernizing our infrastructure and reducing our environmental impact at a reasonable cost, while providing customers with choices like DSM, conservation and renewable energy programs.

Invest in our utility business

After obtaining stakeholder support, the next phase of our strategy is to invest in our regulated utility businesses. Xcel Energy projects that it will invest approximately $13.4 billion in its utility businesses from 2012 through 2016. Our capital investment plan is expected to modernize our infrastructure, improve system reliability, reduce our impact on the environment, expand the amount of renewable energy available to our customers and meet customer demand. We work hard to make sure these investments provide value to our customers by selecting the most cost effective projects and striving to complete these projects on time, safely and within established budgets. As a result of these investments, Xcel Energy projects that the rate base, or the amount on which Xcel Energy earns a return, will grow at a compounded average annual rate of 7 percent through 2016.

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Earn a fair return on our utility investment

The third phase of our strategy is to earn a fair return on our utility investments. Xcel Energy's regulatory strategy is based on filing reasonable base rate requests designed to provide recovery of costs necessary to operate our business and a reasonable return on investment, along with obtaining regulatory approval for rate riders and DSM programs. A rate rider is a mechanism that allows for recovery of certain costs and returns on investments, without the costs and delays of filing a rate case.

Xcel Energy believes that our public utility commissions will provide reasonable and timely recovery, and this is a key assumption to achieving our financial objectives. Constructive regulatory outcomes over the last several years are evidence of reasonable regulatory treatment and provide us confidence that we are pursuing the right strategy.

Provide an attractive total return
Successful execution of the corporate strategic plan should allow Xcel Energy to deliver an attractive total return to our shareholders. Our value proposition is to deliver an attractive total return of about 10 percent through a combination of earnings growth and dividend yield.

Since 2005, our financial objectives have been to:

- Deliver a long-term annual earnings per share growth rate of 5 percent to 7 percent;
- Deliver an annual dividend increases of 2 percent to 4 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

We have successfully achieved these financial objectives. Our ongoing earnings have grown approximately 7 percent and our dividend has grown approximately 3 percent annually since 2005. In addition, our current senior unsecured debt credit ratings for Xcel Energy and it utility subsidiaries are in the BBB+ to A range.

We believe we are positioned to continue earnings growth of 5 percent to 7 percent and dividend growth of 2 percent to 4 percent at least through 2013. Beyond this timeframe, we anticipate that rate base and earnings growth could moderate. Should this occur, we anticipate having flexibility to increase the dividend at a faster rate in the future, while ensuring a strong balance sheet. Therefore, we believe we are positioned to deliver a 10 percent total return.

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements.

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Xcel Energy's management uses this non-GAAP financial measure to evaluate and provide details of earnings results. Xcel Energy's management believes that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to Xcel Energy's consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

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Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	2011	2010	2009
PSCo	$0.82	$0.86	$0.72
NSP-Minnesota	0.73	0.60	0.64
SPS	0.18	0.17	0.15
NSP-Wisconsin	0.10	0.09	0.10
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.03
Regulated utility — continuing operations	1.87	1.76	1.64
Xcel Energy Inc. and other costs	(0.15)	(0.14)	(0.14)
Ongoing diluted earnings per share	1.72	1.62	1.50
COLI settlement and Medicare Part D	-	(0.01)	(0.01)
Earnings per share from continuing operations	1.72	1.61	1.49
Earnings (loss) per share from discontinued operations	-	0.01	(0.01)
GAAP diluted earnings per share	$1.72	$1.62	$1.48

Xcel Energy’s management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy’s fundamental core earnings power. Xcel Energy’s management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

Ongoing earnings exclude the impact of IRS tax and interest adjustments related to the COLI program, the write-off of previously recognized tax benefits relating to Medicare Part D subsidies due to the enacted Patient Protection and Affordable Care Act and a settlement related to the previously discontinued COLI program. See below under Adjustments to GAAP Earnings and Note 6 to the consolidated financial statements for further discussion.

Adjustments to GAAP Earnings

Impact of the Patient Protection and Affordable Care Act — Medicare Part D — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Based on this provision, Xcel Energy is subject to additional taxes and is required to reverse previously recorded tax benefits in the period of enactment. Xcel Energy expensed approximately $17 million, or $0.04 per share, of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. Xcel Energy does not expect the $17 million of additional tax expense to recur in future periods.

COLI — During 2007, Xcel Energy Inc. and PSCo reached a settlement with the IRS related to a dispute associated with its COLI program. These COLI policies were owned and managed by PSRI. As a follow on to the 2007 IRS COLI settlement, during 2010, they reached an agreement in principle of Xcel Energy Inc.'s and PSCo’s statements of account, dating back to tax year 1993. Upon completion of this review, PSRI recorded a net non-recurring tax and interest charge of approximately $9.4 million in 2010. The Tax Court proceedings were dismissed in December 2010 and January 2011. Upon final cash settlement in 2011, Xcel Energy received $0.7 million and recognized a further reduction of expense of $0.3 million. A closing agreement covering tax years 2003 through 2007 was finalized with the IRS in January 2012.

In 2010, Xcel Energy Inc., PSCo and PSRI entered into a settlement agreement with Provident Life & Accident Insurance Company (Provident) related to all claims asserted by Xcel Energy Inc., PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI program. Under the terms of the settlement, Xcel Energy Inc., PSCo and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company resulting in approximately $0.05 of non-recurring earnings per share in 2010. The $25 million proceeds were not subject to income taxes.

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Earnings Adjusted for Certain Items (Ongoing Earnings)

2011 Comparison with 2010

Xcel Energy — Overall, ongoing earnings increased $0.10 per share for 2011. Ongoing earnings increased primarily due to higher electric margins as a result of warmer than normal summer weather across Xcel Energy's service territories and rate increases in various states. The higher margins were partially offset by expected increases in O&M expenses, depreciation, interest expense and property taxes. The increase in expenses was largely driven by capital investment in Xcel Energy's utility business.

PSCo — PSCo earnings decreased $0.04 per share for 2011. The decrease is due to the implementation of seasonal rates in June 2010 (seasonal rates are higher in the summer months and lower throughout the other months of the year), higher O&M expenses, depreciation expense and property taxes, partially offset by the favorable impact of warmer temperatures in the summer.

NSP-Minnesota — NSP-Minnesota earnings increased $0.13 per share for 2011. The increase is primarily due to higher interim electric rates effective in early 2011, subject to refund, in Minnesota and North Dakota, and conservation program incentives partially offset by higher O&M expenses, depreciation expense (net of regulatory adjustments) and property taxes.

SPS — SPS earnings increased $0.01 per share for 2011. The increase is due to higher electric revenues, primarily due to the Texas retail rate increase effective in the first quarter of 2011, and warmer summer weather, partially offset by higher O&M expenses, depreciation expense and property taxes.

NSP-Wisconsin — NSP-Wisconsin earnings increased $0.01 per share for 2011. The increase is primarily due to higher electric rates, partially offset by higher O&M expenses and depreciation expense.

2010 Comparison with 2009

Xcel Energy — Overall, ongoing earnings increased $0.12 per share for 2010. Higher 2010 ongoing earnings were primarily due to improved electric margins as a result of new rates in various jurisdictions and warmer summer temperatures, which were partially offset by higher O&M expenses and property taxes.

PSCo — PSCo earnings increased $0.14 per share for 2010. The increase was due to higher electric margin resulting from the full effect of two general rate increases, and warmer temperatures, which increased electric sales. The rate increases reflect the significant capital investments that PSCo has made in its utility operations. In addition, PSCo's electric operations substantially under-earned its authorized return in 2009. The higher electric margin was partially offset by higher O&M expenses, higher property tax expense and depreciation expense.

NSP-Minnesota — NSP-Minnesota earnings decreased $0.04 per share for 2010. The decrease was primarily due to higher O&M expenses, property taxes and depreciation expense partially offset by the positive impact of warmer temperatures, higher earned incentives on energy efficiency and conservation programs and modest normalized sales growth.

SPS — SPS earnings increased $0.02 per share in 2010. The increase was primarily due to electric sales growth, particularly in the commercial and industrial customer class, the reversal of previously established fuel reserves following the regulatory approval of certain settlement agreements and lower interest expense, which was partially offset by higher O&M expenses.

NSP-Wisconsin — NSP-Wisconsin earnings decreased $0.01 per share for 2010. The decrease was primarily due to fuel recovery and higher O&M expenses, partially offset by warmer temperatures which increased electric sales, as well as new electric rates, that were effective in January 2010.

Equity Earnings of Unconsolidated Subsidiaries — The increase was primarily related to increased earnings from the equity investment in WYCO related to a natural gas storage facility that began operating in mid-2009.

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Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in the diluted EPS compared with prior periods, which are discussed in more detail later.

Diluted Earnings (Loss) Per Share	Dec. 31
2010 GAAP diluted earnings per share	$ 1.62
Earnings per share from discontinued operations	(0.01)
2010 diluted earnings per share from continuing operations	1.61
COLI settlement and Medicare Part D	0.01
2010 ongoing diluted earnings per share	1.62
Components of change — 2011 vs. 2010	
Higher electric margins	0.44
Higher natural gas margins	0.04
Higher operating and maintenance expenses	(0.11)
Dilution from DSPP, benefit plans and the 2010 common equity issuance	(0.08)
Higher taxes (other than income taxes)	(0.06)
Higher conservation and DSM expenses (generally offset in revenues)	(0.05)
Higher depreciation and amortization	(0.04)
Other, net (including interest and premium on redemption of preferred stock)	(0.04)
2011 GAAP and ongoing diluted earnings per share	$ 1.72

Diluted Earnings (Loss) Per Share	Dec. 31
2009 GAAP diluted earnings per share	$ 1.48
PSRI	0.01
2009 diluted earnings per share from continuing operations	1.49
Loss per share from discontinued operations	0.01
2009 ongoing diluted earnings per share	1.50
Components of change — 2010 vs. 2009	
Higher electric margins	0.55
Higher natural gas margins	0.03
Higher operating and maintenance expenses	(0.20)
Higher conservation and DSM expenses (generally offset in revenues)	(0.08)
Higher depreciation and amortization	(0.05)
Lower AFUDC — equity	(0.04)
Higher taxes (other than income taxes)	(0.03)
Dilution from DSPP, benefit plans and the 2010 common equity issuance	(0.02)
Higher interest charges	(0.02)
Other, net	(0.02)
2010 ongoing diluted earnings per share	1.62
COLI settlement and Medicare Part D	(0.01)
2010 diluted earnings per share from continuing operations	1.61
Earnings per share from discontinued operations	0.01
2010 GAAP diluted earnings per share	$ 1.62

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The following table provides a reconciliation of ongoing and GAAP earnings and earnings per diluted share for the years ended Dec. 31:

(Millions of Dollars)	2011	2010	2009
Ongoing earnings	$840.9	$756.4	$690.0
COLI settlement and Medicare Part D	0.5	(4.5)	(4.5)
Total continuing operations	841.4	751.9	685.5
Income (loss) from discontinued operations	(0.2)	3.9	(4.6)
GAAP earnings	$841.2	$755.8	$680.9

Diluted Earnings (Loss) Per Share	2011	2010	2009
Ongoing diluted earnings per share (a)	$1.72	$1.62	$1.50
COLI settlement and Medicare Part D	-	(0.01)	(0.01)
Earnings per share from continuing operations (a)	1.72	1.61	1.49
Earnings (loss) per share from discontinued operations	-	0.01	(0.01)
GAAP diluted earnings per share (a)	$1.72	$1.62	$1.48

(a) Includes the dividend requirements on preferred stock.

Continuing operations consist of the following:

- Regulated utility subsidiaries, operating in the electric and natural gas segments; and
- Other nonregulated subsidiaries and Xcel Energy Inc.

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

	Contributions to Income		
(Millions of Dollars)	2011	2010	2009
GAAP income (loss) by segment			
Regulated electric income	$789.0	$665.2	$611.9
Regulated natural gas income	101.8	114.6	108.9
Other income (a)	17.9	32.4	27.2
Segment income — continuing operations	908.7	812.2	748.0
Xcel Energy Inc. and other costs (a)	(67.3)	(60.3)	(62.5)
Total income — continuing operations	841.4	751.9	685.5
Income (loss) from discontinued operations	(0.2)	3.9	(4.6)
Total GAAP net income	$841.2	$755.8	$680.9

	Contributions to Diluted Earnings (Loss) Per Share		
	2011	2010	2009
GAAP earnings (loss) by segment			
Regulated electric	$ 1.62	$ 1.43	$ 1.33
Regulated natural gas	0.21	0.24	0.24
Other (a)	0.04	0.08	0.06
Segment earnings per share — continuing operations	1.87	1.75	1.63
Xcel Energy Inc. and other costs (a) (b)	(0.15)	(0.14)	(0.14)
Total earnings per share — continuing operations (b)	1.72	1.61	1.49
Earnings (loss) per share from discontinued operations	-	0.01	(0.01)

Total GAAP earnings per diluted share (b)	$ 1.72	$ 1.62	$ 1.48

[a] Not a reportable segment. Included in all other segment results in Note 16 to the consolidated financial statements.
[b] Includes the dividend requirements on preferred stock.

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Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Regulated Earnings — Unseasonably hot summers or cold winters increase electric and natural gas sales while, conversely, mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit, and cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less weather sensitive.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are as follows:

	2011 vs. Normal	2010 vs. Normal (a)	2011 vs. 2010 (a)	2009 vs. Normal	2010 vs. 2009
HDD	(1.0)%	(4.3)%	3.5 %	0.4 %	(5.0)%
CDD	38.1	11.9	23.4	(10.5)	23.8
THI	37.9	29.9	6.1	(34.5)	95.1

(a) Adjusted for the October 2010 sale of SPS electric distribution assets to the city of Lubbock, Texas.

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010	2009 vs. Normal	2010 vs. 2009
Retail electric	$0.07	$0.04	$0.03	$(0.05)	$0.09
Firm natural gas	0.00	(0.01)	0.01	0.00	(0.01)
Total	$0.07	$0.03	$0.04	$(0.05)	$0.08

Sales Growth (Decline) — The following table summarizes Xcel Energy's sales growth (decline) for actual and weather-normalized sales for the years ended Dec. 31, compared with the previous year:

	Dec. 31, 2011		Dec. 31, 2010	
		Weather		Weather

	Actual	Weather Normalized	Normalized Lubbock (a)	Actual	Weather Normalized	Normalized Lubbock (a)
Electric residential	0.5 %	(0.5) %	0.2 %	4.6 %	0.7 %	0.9 %
Electric commercial and industrial	0.3	0.0	0.7	2.6	1.4	1.6
Total retail electric sales	0.4	(0.1)	0.6	3.1	1.2	1.4
Firm natural gas sales	0.9	(2.5)	N/A	(2.9)	(0.2)	N/A

(a) Adjusted for the October 2010 sale of SPS electric distribution assets to the city of Lubbock, Texas.

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During 2010, Xcel Energy experienced slightly higher than anticipated actual electric residential, commercial and industrial sales on a weather-adjusted basis, as the economy started to improve. Sales in 2011 were lower than anticipated in the residential, commercial and industrial segments due to weak economic recovery. Xcel Energy anticipates that sales in the future will grow at a slower rate than historical levels, due in part to increased conservation activities. Weather-normalized sales for 2012 are projected to grow approximately 0.5 to 1.0 percent for retail electric customers and to remain relatively flat for retail firm natural gas customers.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have little impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2011	2010	2009
Electric revenues	$8,767	$8,452	$7,705
Electric fuel and purchased power	(3,992)	(4,011)	(3,672)
Electric margin	$4,775	$4,441	$4,033

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

Electric Revenues

(Millions of Dollars)	2011 vs. 2010
Revenue requirements for PSCo gas generation acquisition (a)	$ 124
Retail rate increases (net of revenue subject to refund) (b)	102
Transmission revenue	45
Conservation and DSM revenue (offset by expenses)	31
Fuel and purchased power cost recovery	19
Estimated impact of weather	18
Conservation and DSM incentive	14
Trading, including PSCo renewable energy credit sales	(19)
Other, net	(19)
Total increase in electric revenue	$ 315

(a) The increase in revenue requirements for PSCo generation reflects the acquisition of the Rocky Mountain and Blue Spruce natural gas facilities in late 2010. These revenue requirements are partially offset by higher O&M expense, depreciation expense, property taxes and financing costs.

(b) The retail rate increases include final rates in Wisconsin and Texas and interim rates, subject to refund, in Minnesota and North Dakota. The rate increases are net of a provision for refund of approximately $67 million for Minnesota and $2.3 million for North Dakota, based on settlements reached with various parties in both cases. In addition, NSP-Minnesota reduced depreciation expense and revenues by approximately $30 million in the fourth quarter of 2011 to reflect the proposed settlement in the Minnesota electric rate case. These settlements are pending commission decisions in both Minnesota and North Dakota.

2011 Comparison with 2010 — Electric revenues increased primarily due to the cost recovery of the acquisition of the Rocky Mountain and Blue Spruce natural gas facilities at PSCo and retail rate increases in Minnesota, Wisconsin, Texas, North Dakota and Michigan.

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Electric Margin

(Millions of Dollars)	2011 vs. 2010
Revenue requirements for PSCo gas generation acquisition (a)	$ 124
Retail rate increases (net of revenue subject to refund) (b)	102
Conservation and DSM revenue (offset by expenses)	31
Transmission revenue, net of costs	20
Estimated impact of weather	18
Conservation and DSM incentive	14
Non-fuel riders	(5)
Other, net (including firm wholesale and deferred fuel adjustments)	30
Total increase in electric margin	$ 334

(a) The increase in revenue requirements for PSCo generation reflects the acquisition of the Rocky Mountain and Blue Spruce natural gas facilities in late 2010. These revenue requirements are partially offset by higher O&M expense, depreciation expense, property taxes and financing costs.

(b) The retail rate increases include final rates in Wisconsin and Texas and interim rates, subject to refund, in Minnesota and North Dakota. The rate increases are net of a provision for refund of approximately $67 million for Minnesota and $2.3 million for North Dakota, based on settlements reached with various parties in both cases. In addition, NSP-Minnesota reduced depreciation expense and revenues by approximately $30 million in the fourth quarter of 2011 to reflect the proposed settlement in the Minnesota electric rate case. These settlements are pending commission decisions in both Minnesota and North Dakota.

2011 Comparison to 2010 — The increase in electric margin was primarily due to the cost recovery of the acquisition of the Rocky Mountain and Blue Spruce natural gas facilities at PSCo and retail rate increases in Minnesota, Wisconsin, Texas, North Dakota and Michigan.

Electric Revenues

(Millions of Dollars)	2010 vs. 2009
Fuel and purchased power cost recovery	$ 288
Retail rate increases, including seasonal rates (Colorado, Wisconsin, South Dakota and New Mexico)	228
Conservation and DSM revenue and incentive (partially offset by expenses)	72
Estimated impact of weather	65
Retail sales increase (excluding weather impact)	18
Sales mix and demand revenues	16
Non-fuel riders	15
Transmission revenue	14
Trading	2
Firm wholesale	(11)
Other, net	40
Total increase in electric revenue	$ 747

2010 Comparison with 2009 — Electric revenues increased due to higher fuel and purchased power costs, retail rate increases in Colorado, Wisconsin, South Dakota and New Mexico, higher conservation revenue and incentives and warmer than normal summer weather, primarily at NSP-Minnesota.

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Electric Margin

(Millions of Dollars)	2010 vs. 2009
Retail rate increases, including seasonal rates (Colorado, Wisconsin, South Dakota and New Mexico)	$ 228
Conservation and DSM revenue and incentive (partially offset by expenses)	72
Estimated impact of weather	65
Retail sales increase (excluding weather impact)	18
Sales mix and demand revenue	16
Non-fuel riders	15
Firm wholesale	9
Trading	(7)
Other, net	(8)
Total increase in electric margin	$ 408

2010 Comparison to 2009 — The increase in electric margin was due to retail rate increases in Colorado, Wisconsin, South Dakota and New Mexico, warmer than normal summer weather, primarily at NSP-Minnesota and higher conservation revenue and incentives.

Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

(Millions of Dollars)	2011	2010	2009
Natural gas revenues	$1,812	$1,783	$1,866
Cost of natural gas sold and transported	(1,164)	(1,163)	(1,266)
Natural gas margin	$648	$620	$600

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

Natural Gas Revenues

(Millions of Dollars)	2011 vs. 2010
Conservation and DSM revenue (offset by expenses)	$ 13
Estimated impact of weather	9
Return on PSCo gas in storage	4
Retail rate increase (Colorado)	3
Purchased natural gas adjustment clause recovery	3
Retail sales decrease (excluding weather impact)	(5)
Conservation and DSM incentive	(2)
Other, net	4
Total increase in natural gas revenues	$ 29

2011 Comparison to 2010 — Natural gas revenues increased primarily due to higher conservation and DSM rates at NSP-Minnesota and colder weather in 2011 at PSCo and NSP-Minnesota.

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Natural Gas Margin

(Millions of Dollars)	2011 vs. 2010
Conservation and DSM revenue (offset by expenses)	$ 13
Estimated impact of weather	9
Return on PSCo gas in storage	4
Retail rate increase (Colorado)	3
Retail sales decrease (excluding weather impact)	(5)
Conservation and DSM incentive	(2)
Other, net	6
Total increase in natural gas margin	$ 28

2011 Comparison to 2010 — Natural gas margins increased primarily due to increased due to higher conservation and DSM rates at NSP-Minnesota and colder weather in 2011 at PSCo and NSP-Minnesota.

Natural Gas Revenues

(Millions of Dollars)	2010 vs. 2009
Purchased natural gas adjustment clause recovery	$ (100)
Estimated impact of weather	(8)
Retail sales decrease (excluding weather impact)	(2)
Conservation and DSM revenue and incentive	18
Rate increase (Minnesota)	6
Other (including sales mix), net	3
Total decrease in natural gas revenues	$ (83)

2010 Comparison to 2009 — Natural gas revenues decreased primarily due to lower natural gas costs in 2010, partially offset by higher conservation and DSM rates.

Natural Gas Margin

(Millions of Dollars)	2010 vs. 2009
Conservation and DSM revenue and incentive (partially offset by expenses)	$ 18
Rate increase (Minnesota)	6
Estimated impact of weather	(8)
Retail sales decrease (excluding weather impact)	(2)
Other, net	6
Total increase in natural gas margin	$ 20

2010 Comparison to 2009 — Natural gas margins increased mainly due to higher conservation and DSM rates in 2010.

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Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $83.0 million, or 4.0 percent for 2011, compared with 2010, and by $149.2 million, or 7.8 percent for 2010, compared with 2009. The following tables summarize the changes in O&M expenses:

(Millions of Dollars)	2011 vs. 2010
Higher plant generation costs	$ 22
Higher labor and contract labor costs	18
Higher employee benefit expense	13
Higher nuclear plant operation costs	12
Higher insurance costs	4
Other, net	14
Total increase in O&M expenses	$ 83

2011 Comparison to 2010 — The increase in O&M expenses for 2011 was largely driven by the following:

- Higher plant generation costs are attributable to incremental costs associated with new generation placed in service and a higher level of scheduled maintenance and overhaul work.
- Higher labor and contract labor costs are primarily due to maintenance on our distribution facilities and the impact of annual wage increases.
- Higher employee benefit costs are largely driven by higher pension expense.
- Higher nuclear plant operation costs were largely driven by outages.

(Millions of Dollars)	2010 vs. 2009
Higher plant generation costs	$ 47
Higher labor costs	24
Higher nuclear plant operation costs	20
Higher contract labor costs	18
Higher employee benefit expense	15
Higher nuclear outage costs, net of deferral	10
Other, net	15
Total increase in O&M expenses	$ 149

2010 Comparison to 2009 — The increase in O&M expenses for 2010 was largely driven by the following:

- Higher plant generation costs are primarily attributable to the timing of planned maintenance and overhaul work as well as incremental operating costs associated with new generation facilities placed in service in 2010.
- Higher contract labor is primarily related to maintenance on our distribution facilities.
- Higher nuclear plant operation costs are mainly due to increased labor and security expenses.
- Higher labor costs are primarily due to higher overtime for storm restoration work and a shift in labor resources from capital to O&M projects.
- Higher nuclear outage costs are due to the timing and higher cost of nuclear refueling outages.
- Higher employee benefit costs for the year are primarily due to increased pension costs partially offset by lower health care costs.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $41.6 million, or 17.3 percent for 2011, compared with 2010. The higher expense is primarily attributable to an increase in the rider rates used to recover the program expenses. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Overall, the programs are designed to encourage the operating companies and their retail customers to conserve energy or change energy usage patterns in order to reduce peak demand on the gas or electric system. This, in turn, reduces the need for additional plant capacity, reduces emissions, serves to achieve other environmental goals as well as reduces energy costs to participating customers.

Conservation and DSM program expenses increased $57.7 million for 2010, compared with 2009. The higher expense was attributable to the continued expansion of programs and regulatory commitments.

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Depreciation and Amortization — Depreciation and amortization expense increased $31.7 million, or 3.7 percent for 2011, compared with 2010. This increase in depreciation expense is primarily due to several capital projects going into service, including a portion of the Monticello extended power uprate going into service in May 2011, the Nobles wind project commencing commercial operations in late 2010, the acquisition of two PSCo gas generation facilities in December 2010, Jones Unit 3 going into service in June 2011 and normal system expansion. The increase was partially offset due to NSP-Minnesota reducing depreciation expense by approximately $30 million in the fourth quarter of 2011 to reflect the proposed settlement in the Minnesota electric rate case.

Depreciation and amortization expenses increased $40.8 million, or 5.0 percent for 2010, compared with 2009. The change in depreciation expense was primarily due to Comanche Unit 3 going into service and normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $42.9 million, or 12.9 percent for 2011, compared with 2010. The change is primarily due to an increase in 2011 for property taxes of approximately $29.6 million in Colorado and $8.8 million in Minnesota.

Taxes (other than income taxes) increased $25.5 million, or 8.3 percent for 2010, compared with 2009. The change was primarily due to an increase in property taxes in Colorado and in Minnesota.

Other Income, Net — Other income, net decreased $21.9 million for 2011, compared with 2010, and increased $21.4 million for 2010, compared with 2009. The changes were primarily due to the COLI settlement in July 2010.

AFUDC — AFUDC decreased $5.4 million, or 6.4 percent for 2011, compared with 2010. The decrease is primarily due to lower AFUDC rates and lower average CWIP. The lower average CWIP is attributed to Comanche Unit 3 and the Nobles wind project going into service in 2010, offset by Monticello extended power uprate and work at the Jones plant, as well as SPS transmission projects in 2011.

AFUDC decreased $30.7 million for 2010, compared with 2009. The decrease was partially due to Comanche Unit 3 going into service in May 2010, as well as lower interest rates.

Interest Charges — Interest charges increased $13.8 million, or 2.4 percent for 2011, compared with 2010, and $15.6 million, or 2.8 percent for 2010, compared with 2009. The increase was due to higher long-term debt levels necessary to fund investments in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations increased $31.7 million for 2011, compared with 2010. The increase is primarily due to higher pretax income, a net change in tax valuation allowances of $8.9 million, and the non-taxability of the Provident settlement in 2010. These were partially offset by the 2010 write-off of the tax benefit for Medicare Part D subsidies, an adjustment related to COLI and an increase in 2011 wind production tax credits. The effective tax rate for continuing operations was 35.8 percent for 2011, compared with 36.7 percent for 2010. The higher effective tax rate for 2010 was primarily due to the Medicare Part D, COLI, and the valuation allowance adjustments referenced above. Without these adjustments, the effective tax rate for continuing operations for 2010 would have been 35.1 percent. See Note 6 in the notes to consolidated financial statements for further discussion on COLI.

Income tax expense for continuing operations increased $65.3 million for 2010, compared with 2009. The increase in income tax expense was primarily due to an increase in pretax income, and one time adjustments for a write-off of tax benefit previously recorded for Medicare Part D subsidies and an adjustment related to the COLI Tax Court proceedings. This was partially offset by a reversal of a valuation allowance for certain state tax credit carryovers. The effective tax rate for continuing operations was 36.7 percent for 2010 compared with 35.1 percent for

2009. The higher effective tax rate for 2010 was primarily due to the adjustments referenced above. The effective tax rate for ongoing earnings for 2010 was 35.3 percent.

Premium on Redemption of Preferred Stock — Xcel Energy Inc. redeemed all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions to earnings available to common shareholders for 2011.

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Xcel Energy Inc. and Other Results

The following tables summarize the net income and earnings per share contributions of the continuing operations of Xcel Energy Inc. and its nonregulated businesses:

	Contribution to Xcel Energy's Earnings		
(Millions of Dollars)	2011	2010	2009
Xcel Energy Inc. financing costs	$(63.8)	$(68.7)	$(65.6)
Eloigne	(2.9)	5.4	(4.7)
Xcel Energy Inc. taxes and other results	(0.6)	3.0	7.8
Total Xcel Energy Inc. and other costs — continuing operations	(67.3)	(60.3)	(62.5)
Preferred dividends	(6.8)	(4.2)	(4.2)
Total Xcel Energy Inc. and other costs, available to common shareholders	$(74.1)	$(64.5)	$(66.7)

	Contribution to Xcel Energy's Earnings per Share		
(Earnings per Share)	2011	2010	2009
Xcel Energy Inc. financing costs	$ (0.13)	$ (0.15)	$ (0.14)
Eloigne	(0.01)	0.01	(0.01)
Xcel Energy Inc. taxes and other results	0.00	0.01	0.02
Preferred dividends	(0.01)	(0.01)	(0.01)
Total Xcel Energy Inc. and other costs — continuing operations	$ (0.15)	$ (0.14)	$ (0.14)

Xcel Energy Inc.'s results include interest expense and the earnings per share impact of preferred dividends, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

General Economic Conditions

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

Fuel Supply and Costs

Xcel Energy's operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax and unanticipated changes in regulatory recovery mechanisms could impact our operations. See Item 1 for further discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

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

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Regulation

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

The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Because comprehensive general rate changes are not requested annually in some states, changes in operating costs can affect Xcel Energy's financial results. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales growth, which is affected by overall economic conditions, conservation and DSM efforts and the cost of capital. In addition, the ROE authorized is set by regulatory commissions in rate proceedings.

Wholesale Energy Market Regulation — Wholesale energy markets in the Midwest are operated by MISO to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. NSP-Minnesota and NSP-Wisconsin expect to recover MISO charges through either base rates or various recovery mechanisms. See Note 12 to the consolidated financial statements for further discussion.

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

Environmental Matters

Environmental costs include payments for nuclear plant decommissioning, storage and disposal of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to Xcel Energy's air emissions. A trend of greater environmental awareness and increasingly stringent regulation may continue to cause, higher operating expenses and capital expenditures for environmental compliance.

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

- $265 million in 2011;
- $256 million in 2010; and
- $225 million in 2009.

Xcel Energy estimates an average annual expense of approximately $317 million from 2012 through 2016 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 may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $48 million in 2011;
- $473 million in 2010; and
- $89 million in 2009.

See Item 7 — Capital Requirements for further discussion.

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Xcel Energy's operations are subject to air, water, and particulate matter state laws and regulations. These laws and regulations regulate air emissions from various sources, including electrical generating units, and impose certain monitoring and reporting requirements. Such laws and regulations may require Xcel Energy to obtain pre-approval for the construction or modification of certain projects that increase air emissions, obtain and strictly comply with air permits that contain emission and operational limitations or mandate the installation and operation of expensive pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation plans of MGP sites and various regulations for air emissions and water intake. Actual expenditures could be higher or lower than the estimates presented, and the scope and timing of these expenditures cannot be fully determined until any new or revised regulations become final.

In July 2011, the EPA issued the CSAPR, to address long-range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. On Dec. 30, 2011, the D.C. Circuit issued a stay of the CSAPR, pending completion of judicial review of the rule. The states in which Xcel Energy operates are currently considering SIPs which may be superseded by CAIR and/or CSAPR. Xcel Energy is in the process of determining various scenarios to respond to the CSAPR uncertainty.

In addition, there are emission controls, known as BART, for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas throughout the U.S. Xcel Energy generating facilities in several states will be subject to BART requirements.

Further, generating facilities throughout the Xcel Energy territory are subject to mercury reduction requirements at the state level. In December 2011, the EPA adopted a regulation setting national emission limits for electric generating units for mercury, certain metals, and acid gas emissions.

See Note 13 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation resulting from the economic and monetary stimulus policies of the U.S. Government and the Federal Reserve could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment may have a significant effect on the operation of our business and on the results reported even if the nature of the accounting policies applied have not changed. The following is a list of accounting policies that are most critical to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher potential likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been discussed with the Audit Committee of the Xcel Energy Inc.'s Board of Directors.

Regulatory Accounting

Xcel Energy Inc. is a holding company with rate-regulated subsidiaries that are subject to the accounting for Regulated Operations, which provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets represent incurred or accrued costs that have been deferred because they are probable of future recovery from customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or OCI.

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As of Dec. 31, 2011 and 2010, Xcel Energy has recorded regulatory assets of $2.8 billion and $2.5 billion and regulatory liabilities of $1.4 billion and $1.3 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. While there are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets, if the SEC should mandate the use of IFRS the lack of an accounting standard for rate-regulated entities under IFRS could require us to charge certain regulatory assets and regulatory liabilities to net income or OCI. See Note 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities.

Income Tax Accruals

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

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

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

Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. The change in the unrecognized tax benefits needs to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimated range of reasonably possible changes. At any period end, and as new developments occur, management will use prudent business judgment to derecognize appropriate amounts of tax benefits. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline.

As disputes with the IRS and state tax authorities are resolved over time, we may need to adjust our unrecognized tax benefits and interest accruals to the updated estimates needed to satisfy tax and interest obligations for the related issues. These adjustments may be favorable or unfavorable, increasing or decreasing earnings. See Note 6 to the consolidated financial statements for further discussion.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. See Note 9 to the consolidated financial statements for further discussion on the rate of return and discount rate used in the calculation of pension costs and obligations.

Pension costs and funding requirements are expected to increase in the next few years. While investment returns exceeded the assumed levels from 2009-2011, investment returns in 2007 and 2008 were significantly below the assumed levels. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized over the expected average remaining years of service for active employees.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes will increase from an expense of $47.8 million in 2010 and an expense of $81.0 million in 2011 to an expense of $124.1 million in 2012 and expense of $138.1 million in 2013. The expected increase in the 2012 expense is due to the continued phase in of unrecognized plan losses primarily resulting from the market decline in 2008.

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At Dec. 31, 2011, Xcel Energy set the rate of return used to measure pension costs at 7.5 percent, which is a 29 basis point decrease from Dec. 31, 2010. The rate of return used to measure postretirement health care costs of 7.5 percent at Dec. 31, 2011 was unchanged from Dec. 31, 2010.

Xcel Energy set the discount rate used to value the Dec. 31, 2011 pension and postretirement health care obligations at 5.0 percent, which is a 50 basis point decrease from Dec. 31, 2010. Xcel Energy uses multiple reference points in determining the discount rate, including Citigroup Pension Liability Discount Curve, the Citigroup Above Median Curve and bond matching studies. At Dec. 31, 2011, these reference points supported the selected rate. In addition to these reference points, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. The following are the pension funding contributions, both voluntary and required, made by Xcel Energy for 2010 through 2012:

- In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans;
- In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans;
- In 2010, contributions of $34 million were made to the Xcel Energy Pension Plan.
- For future years, we anticipate contributions will be made as necessary.

These expected contributions are summarized in Note 9 to the consolidated financial statements. These amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2011, a one-percent change would result in the following impact on 2012 pension expense:

	Pension Costs	
(Millions of Dollars)	+1%	-1%
Rate of return	$ (29.1)	$ 29.6
Discount rate	(16.5)	19.2

Effective Dec. 31, 2011, Xcel Energy reduced its initial medical trend assumption from 6.5 percent to 6.3 percent. The ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached remained unchanged at eight years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed $49.0 million and $48.4 million during 2011 and 2010, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately $39.1 million during 2012.

Xcel Energy recovers employee benefits costs in its regulated utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions based on expense as calculated using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated are deferred as a regulatory liability.
-

Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other post retirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.

See Note 9 to the consolidated financial statements for further discussion.

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Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions used to estimate AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset. Xcel Energy accretes ARO liabilities to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The total obligation for nuclear decommissioning currently is expected to be funded 100 percent by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and amounts recorded under current accounting guidance are deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $1,482.7 million and $809.5 million as of Dec. 31, 2011 and 2010, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic site-specific cost studies in order to estimate the nature, cost and timing of planned nuclear decommissioning activities. These independent third party cost studies are based on relevant information available at the time performed; however, estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results.

In December 2011, NSP-Minnesota submitted to the MPUC its triennial nuclear decommissioning filing. The filing includes a current decommissioning study, which covers all expenses over the estimated lives of the nuclear plants, including decontamination and removal of radioactive material. The estimated future costs are initially determined in nominal amounts prior to escalation adjustments, then future periods' costs are escalated using decommissioning-specific cost escalators and finally discounted using risk-free, credit adjusted interest rates.

The following key assumptions have a significant effect on these estimates:

- Timing — Decommissioning cost estimates are impacted by each facility's retirement date, as well as the expected timing of the actual decommissioning activities. Currently, the estimated retirement dates coincide with each units operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for Prairie Island's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon a methodology required by the MPUC (i.e., DECON method). By utilizing this method, which assumes prompt removal and dismantlement, these activities are expected to begin at the end of the license date and be completed for both facilities by 2067.

- Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's 2011 nuclear decommissioning filing assumes current technology and regulations.

- Escalation Rates — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 3.63 percent in calculating the AROs related to nuclear decommissioning for the remaining operational period through the radiological decommissioning period. An escalation rate of 2.63 percent was utilized for the period of operating costs related to interim dry cask storage of spent nuclear fuel and site restoration.

- Discount Rates — Changes in timing or estimated expected cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the asset retirement obligation, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. The estimated expected cash flows that changed as a result of the 2011 triennial nuclear decommissioning filing resulted in upward revisions to the ARO. As such, the new cost layer was calculated using a 4.33 percent credit-adjusted risk-free rate.

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Significant uncertainties exist in estimating the future cost of nuclear decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially. However, changes in estimates have minimal impact on results of operations as we expect to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2011.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and nonperformance risk. Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

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

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

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31, were as follows:

(Thousands of Dollars)	2011	2010
Fair value of commodity trading net contract assets outstanding at Jan. 1	$20,249	$9,628
Contracts realized or settled during the period	(10,672)	(4,449)
Unrealized commodity trading transactions during the period	10,847	15,070
Fair value of commodity trading net contract assets outstanding at Dec. 31	$20,424	$20,249

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At Dec. 31, 2011, the fair values by source for the commodity trading net asset balance were as follows:

		Futures / Forwards				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$4,317	$ 14,843	$ -	$ -	$ 19,160
PSCo	1	474	790	-	-	1,264
		$4,791	$ 15,633	$ -	$ -	$ 20,424

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

At Dec. 31, 2011, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.2 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.2 million.

Xcel Energy's short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions. The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2011	$0.09	$3.00	$0.14	$0.33	$0.04
2010	0.15	3.00	0.22	0.64	0.03

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options. At Dec. 31, 2011, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million related to expected 2012 debt issuances.

At Dec. 31, 2011, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $2.9 million annually. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

Xcel Energy also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2011, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2011, a 10 percent increase in prices would have resulted in an increase in credit exposure of $1.3 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $4.3 million.

Xcel Energy Inc. 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. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

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Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and generally requires that the most observable inputs available be used for fair value measurements. See Note 11 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2011. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues when necessary. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2011.

Commodity derivative assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long-term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent immaterial percentages of total assets and liabilities measured at fair value at Dec. 31, 2011.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $13.3 million and $0.9 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2011.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 commodity forwards or options held at Dec. 31, 2011.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities, private equity investments and real estate investments. To the extent appropriate, observable market inputs are utilized to estimate the fair value of asset-backed and mortgage-backed securities; however, less observable and subjective inputs are often significant to these valuations, including risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated prepayments of principal. Measurement of private equity investments and real estate investments at net asset value requires significant use of unobservable inputs when determining the fair value of the underlying fund investments, including equity in non-publicly traded entities and real estate properties. Therefore, estimated fair values for asset-backed and mortgage-backed securities, private equity investments and real estate investments totaling $130.8 million in the nuclear decommissioning fund at Dec. 31, 2011 (approximately 9.4 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

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Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2011	2010	2009
Net cash provided by operating activities	$2,406	$1,894	$1,913

Net cash provided by operating activities increased by $512 million for 2011 as compared to 2010. The increase was a result of higher net income, changes in working capital due to timing of payments and the receipt of the nuclear waste disposal settlement of $100 million. These increases were partially offset by a $103 million increase between the periods in pension contributions.

Net cash provided by operating activities decreased by $19 million for 2010 as compared to 2009. The decrease was primarily due to changes in working capital partially offset by higher net income and lower pension contributions made in 2010.

(Millions of Dollars)	2011	2010	2009
Net cash used in investing activities	$(2,248)	$(2,807)	$(1,735)

Net cash used in investing activities decreased by $559 million for 2011 as compared to 2010. The decrease was mainly due to the acquisition of generation assets in 2010 partially offset by a change in restricted cash due to the receipt of the $100 million nuclear waste disposal settlement.

Net cash used in investing activities increased by $1.1 billion during 2010 as compared to 2009. This increase was primarily due to the acquisition of two natural-gas fired generation facilities and increased investment in utility operations primarily at PSCo, including the completion of Comanche Unit 3.

(Millions of Dollars)	2011	2010	2009
Net cash (used in) provided by financing activities	$(205)	$906	$(322)

Net cash used in financing activities increased by $1.1 billion during 2011 as compared to 2010. The increase was primarily due to lower proceeds from the issuance of long-term debt and common stock in 2011 and the redemption of preferred stock during 2011.

Net cash provided by financing activities increased by $1.2 billion during 2010 as compared to 2009. The increase was primarily attributable to higher proceeds from the issuance of long-term debt and common stock.

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

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Capital Requirements

Utility Capital Expenditures — The estimated cost of the capital expenditure programs of Xcel Energy Inc. and its subsidiaries, excluding discontinued operations, and other capital requirements for the years 2012 through 2016 is shown in the tables below.

(Millions of Dollars)	2012	2013	2014	2015	2016
By Subsidiary					
NSP-Minnesota	$1,130	$1,390	$1,150	$1,040	$1,200
PSCo	900	1,020	920	730	720
SPS	460	730	430	320	340
NSP-Wisconsin	160	160	200	210	190
Total capital expenditures	$2,650	$3,300	$2,700	$2,300	$2,450

By Function	2012	2013	2014	2015	2016
Electric transmission	$710	$945	$740	$660	$710
Electric generation	570	680	495	450	345
Electric distribution	445	400	420	460	465
Environmental	300	690	410	190	270
Natural gas	245	275	275	225	245
Nuclear fuel	145	95	160	105	245
Other	235	215	200	210	170
Total capital expenditures	$2,650	$3,300	$2,700	$2,300	$2,450

By Project	2012	2013	2014	2015	2016
Base and other capital expenditures	$1,850	$1,815	$1,690	$1,670	$2,030
PSCo CACJA	200	410	260	95	10
CapX2020	175	350	285	145	-
Nuclear fuel	145	95	160	105	245
Nuclear capacity increases and life extension	145	295	105	95	-
CSAPR (a)	75	255	115	25	-
RES and infrastructure investments	60	80	85	165	165
Total capital expenditures (b)	$2,650	$3,300	$2,700	$2,300	$2,450

(a) In July 2011, the EPA issued its CSAPR, to address long range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. On Dec. 30, 2011, the D.C. Circuit issued a stay of the CSAPR, pending completion of judicial review of the rule. Xcel Energy is in the process of determining various scenarios to respond to the CSAPR depending on whether the CSAPR is upheld, reversed, or modified. Capital requirements may vary depending on the final resolution. See Note 13 to the consolidated financial statements for further discussion of CSAPR.

(b) The industry is considering a wide range of strategies to address anticipated NRC regulation. Depending on the approach selected, preliminary estimates range from $20 million to $250 million dollars of capital investment approximately over the next five years to address postulated safety upgrades to the Xcel Energy nuclear facilities. Capital requirements may vary depending on the final regulation, therefore estimated costs are not included in the table above. See Item 1 for further discussion of NRC regulation.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margins, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with future environmental requirements and RPS to install emission-control equipment, and merger, acquisition and divestiture opportunities to support corporate strategies.

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Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2011. See the statements of capitalization and additional discussion in Notes 4 and 13 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 (a)	$18,489,722	$1,583,410	$1,431,936	$1,323,435	$14,150,941
Capital lease obligations	395,540	18,198	36,007	35,111	306,224
Operating leases (b)(c)	2,984,448	185,690	403,181	397,325	1,998,252
Unconditional purchase obligations	10,585,365	1,866,553	2,519,295	1,875,066	4,324,451
Other long-term obligations, including current portion (d)	108,874	28,481	52,244	28,149	-
Payments to vendors in process	23,363	23,363	-	-	-
Short-term debt	219,000	219,000	-	-	-
Total contractual cash obligations (e) (f) (g) (h)	$32,806,312	$3,924,695	$4,442,663	$3,659,086	$20,779,868

(a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2011, and outstanding principal for each investment with the terms ending at each instrument's maturity.

(b) 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, 2011, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $85.3 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(c) Included in operating lease payments are $159.0 million, $354.1 million, $355.9 million and $1.9 billion, for the less than 1 year, 1-3 years, 4-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(d) Other long-term obligations relate primarily to amounts associated with technology agreements as well as uncertain tax positions.

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

(f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately $1.8 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table.

(g) In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans.

(h) Xcel Energy expects to contribute approximately $39.1 million to the postretirement health care plans during 2012.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. Xcel Energy's objective is to continue to grow earnings 5 percent to 7 percent and to grow the dividend 2 percent to 4 percent annually, at least through 2013. Beyond this timeframe, we anticipate that rate base and earnings growth could be moderate. Should this occur, we anticipate having flexibility to increase the dividend at a faster rate in the future. Xcel Energy's dividend policy balances:

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

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

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants.

Xcel Energy Inc.'s Articles of Incorporation place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Xcel Energy Inc. redeemed all outstanding preferred stock in 2011. In addition, Xcel Energy Inc.'s Junior Subordinated Indenture places restrictions on its ability to declare and pay dividends in the event Xcel Energy Inc. defers the payment of all or part of the current and accrued interest on its Junior Subordinated Notes due 2068. As of Dec. 31, 2011, Xcel Energy Inc. has paid all current and accrued interest.

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Regulation of Derivatives — In July 2010, financial reform legislation was passed, which provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements. Additionally there may be material increased reporting requirements. The bill contains provisions that should exempt certain derivatives end users from much of the clearing and margining requirements. However, the CFTC is still developing the regulatory rules under the act and, it is not clear whether Xcel Energy will qualify for the exemption. In addition, although the CFTC's proposed rules would extend the end user exemption to margin requirements, they would impose a requirement to have credit support agreements in their place. If Xcel Energy does not meet the end user exception, the margin requirements could be significant. The full implications for Xcel Energy can not yet be determined until the various definitions and rulemakings are completed.

FERC Order 741 addresses rulemaking addressing the credit policies of organized electric markets and limits the amount of overall credit available to entities operating and places restrictions on netting of transactions within organized markets unless certain market protocols are implemented by the RTO. The various RTOs are in the process of filing their proposed market protocols to satisfy FERC Order 741 and these new market designs may lead to additional margin requirements that could impact our liquidity.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short–term to long-duration fixed income securities, and alternative investments, including, private equity, real estate and commodity index investments. In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans. In 2010, contributions of $34 million were made to the Xcel Energy Pension Plan. For future years, we anticipate contributions will be made as necessary. The funded status and pension assumptions are summarized in the following tables:

(Millions of Dollars)	Dec. 31, 2011	Dec. 31, 2010
Fair value of pension assets	$ 2,670	$ 2,541
Projected pension obligation (a)	3,226	3,030
Funded status	$ (556)	$ (489)

(a) Excludes non-qualified plan of $55 million and $47 million at Dec. 31, 2011 and 2010, respectively.

Pension Assumptions	2012	2011
Discount rate	5.00 %	5.50 %
Expected long-term rate of return	7.10	7.50

Capital Sources

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

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Dec. 31, 2011, approximately $6.1 million of cash was held in these liquid operating accounts.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. NSP-Wisconsin received regulatory approval to initiate a commercial paper program beginning in 2011. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $300 million for SPS; and
- $150 million for NSP-Wisconsin.

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Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450
Amount outstanding at period end	219
Average amount outstanding	165
Maximum amount outstanding	241
Weighted average interest rate, computed on a daily basis	0.35%
Weighted average interest rate at end of period	0.40

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2011	Twelve Months Ended Dec. 31, 2010	Twelve Months Ended Dec. 31, 2009
Borrowing limit	$ 2,450	$ 2,177	$ 2,177
Amount outstanding at period end	219	466	459
Average amount outstanding	430	263	406
Maximum amount outstanding	824	653	675
Weighted average interest rate, computed on a daily basis	0.36%	0.36%	0.95%
Weighted average interest rate at end of period	0.40	0.40	0.36

Commercial paper borrowings during 2011 were used for general operating activities, capital expenditures, redemption of preferred stock and timing differences between debt maturities and refinancings.

Credit Facilities — During 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new four-year credit agreements. The total capacity of the credit facilities increased approximately $273 million to $2.45 billion. As of Feb. 17, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility (a)	Drawn (b)	Available	Cash	Liquidity
Xcel Energy Inc.	$800.0	$244.1	$555.9	$0.1	$556.0
PSCo	700.0	5.0	695.0	44.1	739.1
NSP-Minnesota	500.0	7.6	492.4	0.5	492.9
SPS	300.0	-	300.0	0.8	300.8
NSP-Wisconsin	150.0	49.0	101.0	1.1	102.1
Total	$2,450.0	$305.7	$2,144.3	$46.6	$2,190.9

(a) These credit facilities expire March 2015.
(b) Includes outstanding commercial paper and letters of credit.

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated during consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

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Registration Statements — Xcel Energy Inc.’s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2011 and 2010, Xcel Energy Inc. had approximately 486 million shares and 482 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.’s Articles of Incorporation authorize the issuance of seven million shares of $100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2011 and approximately one million shares of preferred stock outstanding on Dec. 31, 2010. Xcel Energy Inc. and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy Inc. has an effective automatic shelf registration statement that does not contain a limit on issuance capacity. However, Xcel Energy Inc.’s ability to issue securities is limited by authority granted by the Board of Directors, which currently authorizes the issuance of up to an additional $1.75 billion of debt and common equity securities.
- NSP-Minnesota has a shelf registration statement filed in January 2011. NSP-Minnesota’s ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to $1.5 billion of debt securities.
- PSCo has an automatic shelf registration statement filed in October 2010 that does not contain a limit on issuance capacity. However, PSCo’s ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to $1.15 billion of debt securities.

Long-Term Borrowings — See the consolidated statements of capitalization and a discussion of the long-term borrowings in Note 4 to the consolidated financial statements.

During 2011, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In August 2011, PSCo issued $250 million of 30-year first mortgage bonds with a coupon of 4.75 percent. PSCo used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term debt borrowings incurred to fund daily operational needs. The balance of the net proceeds was used for general corporate purposes.
- In August 2011, SPS issued $200 million of 30-year first mortgage bonds with a coupon of 4.5 percent. SPS used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term debt borrowings incurred to fund daily operational needs and to redeem $57.3 million of the outstanding 5.75 percent pollution control revenue refunding bonds in September 2011. The balance of the net proceeds was used for general corporate purposes.
- In September 2011, Xcel Energy Inc. issued $250 million of 30-year unsecured bonds with a coupon of 4.8 percent. Xcel Energy Inc. added the net proceeds from the sale of the notes to its general funds and used the proceeds to repay short-term debt and for general corporate purposes.
- In October 2011, Xcel Energy Inc. redeemed all series of its preferred stock, which had a par value of $105 million.

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

During 2012, Xcel Energy Inc. and its utility subsidiaries anticipate issuing following:

- NSP-Minnesota may issue approximately $800 million of first mortgage bonds in the third quarter of 2012.
- PSCo may issue approximately $750 million of first mortgage bonds in the third quarter of 2012.
- SPS may issue approximately $100 million of first mortgage bonds in the first half of 2012.
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds in the second half of 2012.

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

Off-Balance-Sheet Arrangements

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

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Earnings Guidance

Xcel Energy expects its 2012 ongoing earnings will be in the lower half of the guidance range of $1.75 to $1.85 per share. Key assumptions related to ongoing earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales are projected to grow 0.5 to 1.0 percent.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Rider revenue recovery is projected to increase approximately $50 million to $60 million over 2011 levels.
- O&M expenses are projected to increase approximately 1.0 to 3.0 percent over 2011 levels.
- Depreciation expense is projected to increase $60 million to $70 million over 2011 levels. This assumes depreciation expense in both 2011 and 2012 is reduced by $30 million, consistent with the settlement agreement in the Minnesota electric rate case, which is pending a MPUC decision.
- Property taxes are projected to increase by $20 million to $25 million over 2011 levels, net of NSP-Minnesota's request for deferred accounting for 2012 property tax increases, which is pending a MPUC decision.
- Interest expense (net of AFUDC — debt) is projected to be relatively flat.
- AFUDC — equity is projected to increase approximately $25 million to $30 million over 2011 levels.
- The effective tax rate is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 488 million shares.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 for an index of financial statements included herein.

See Note 17 to the consolidated financial statements for summarized quarterly financial data.

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Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'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 Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2011. 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, 2011, Xcel Energy Inc.'s internal control over financial reporting is effective based on those criteria.

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

/S/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Chairman, President and Chief Executive Officer
February 24, 2012

/S/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the 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. and subsidiaries (the “Company”) as of December 31, 2011 and 2010, and the related consolidated statements of income, common stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 24, 2012

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011 of the Company and our report dated February 24, 2012 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 24, 2012

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2011	2010	2009
Operating revenues			
Electric	$8,766,593	$8,451,845	$7,704,723
Natural gas	1,811,926	1,782,582	1,865,703
Other	76,251	76,520	73,877
Total operating revenues	10,654,770	10,310,947	9,644,303
Operating expenses			
Electric fuel and purchased power	3,991,786	4,010,660	3,672,490
Cost of natural gas sold and transported	1,163,890	1,162,926	1,266,440
Cost of sales — other	30,391	29,540	22,107
Operating and maintenance expenses	2,140,289	2,057,249	1,908,097
Conservation and demand side management program expenses	281,378	239,827	182,112
Depreciation and amortization	890,619	858,882	818,052
Taxes (other than income taxes)	374,815	331,894	306,433
Total operating expenses	8,873,168	8,690,978	8,175,731
Operating income	1,781,602	1,619,969	1,468,572
Other income, net	9,255	31,143	9,771
Equity earnings of unconsolidated subsidiaries	30,527	29,948	24,664
Allowance for funds used during construction — equity	51,223	56,152	75,686
Interest charges and financing costs			
Interest charges — includes other financing costs of $24,019, $20,638, and $20,162, respectively	591,098	577,291	561,654
Allowance for funds used during construction — debt	(28,181)	(28,670)	(39,799)
Total interest charges and financing costs	562,917	548,621	521,855
Income from continuing operations before income taxes	1,309,690	1,188,591	1,056,838
Income taxes	468,316	436,635	371,314
Income from continuing operations	841,374	751,956	685,524
Income (loss) from discontinued operations, net of tax	(202)	3,878	(4,637)
Net income	841,172	755,834	680,887
Dividend requirements on preferred stock	3,534	4,241	4,241
Premium on redemption of preferred stock	3,260	-	-
Earnings available to common shareholders	$834,378	$751,593	$676,646
Weighted average common shares outstanding:			
Basic	485,039	462,052	456,433
Diluted	485,615	463,391	457,139
Earnings per average common share — basic:			
Income from continuing operations	$1.72	$1.62	$1.49

Income (loss) from discontinued operations	-	0.01	(0.01)
Earnings per share	$1.72	$1.63	$1.48
Earnings per average common share — diluted:			
Income from continuing operations	$1.72	$1.61	$1.49
Income (loss) from discontinued operations	-	0.01	(0.01)
Earnings per share	$1.72	$1.62	$1.48
Cash dividends declared per common share	$1.03	$1.00	$0.97

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2011	2010	2009
Operating activities			
Net income	$841,172	$755,834	$680,887
Remove (income) loss from discontinued operations	202	(3,878)	4,637
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	908,853	872,186	835,597
Conservation and demand side management program amortization	9,816	21,700	29,418
Nuclear fuel amortization	100,902	105,369	80,104
Deferred income taxes	466,567	414,460	407,517
Amortization of investment tax credits	(6,194)	(6,353)	(6,426)
Allowance for equity funds used during construction	(51,223)	(56,152)	(75,686)
Equity earnings of unconsolidated subsidiaries	(30,527)	(29,948)	(24,664)
Dividends from unconsolidated subsidiaries	34,034	32,538	29,059
Provision for bad debts	44,521	44,068	49,023
Share-based compensation expense	45,006	35,807	29,672
Net derivative losses (gains)	9,966	(35,552)	39,029
Changes in operating assets and liabilities:			
Accounts receivable	(79,701)	(29,749)	122,503
Accrued unbilled revenues	19,951	(14,642)	49,430
Inventories	(57,432)	9,239	100,504
Other current assets	62,458	10,461	(84,783)
Accounts payable	13,748	(188,855)	(50,638)
Net regulatory assets and liabilities	149,282	36,096	(38,403)
Other current liabilities	112,353	13,192	49,388
Pension and other employee benefit obligations	(150,717)	(62,625)	(245,987)
Change in other noncurrent assets	24,069	5,936	(1,991)
Change in other noncurrent liabilities	(61,584)	(35,190)	(65,284)
Net cash provided by operating activities	2,405,522	1,893,942	1,912,906
Investing activities			
Utility capital/construction expenditures	(2,205,567)	(2,216,193)	(1,777,608)
Allowance for equity funds used during construction	51,223	56,152	75,686
Merricourt refund	101,261	-	-
Merricourt deposit	(90,833)	(1,134)	(9,294)
Purchase of investments in external decommissioning fund	(2,098,642)	(3,781,438)	(1,644,278)
Proceeds from the sale of investments in external decommissioning fund	2,098,642	3,786,373	1,664,957
Proceeds from the sale of assets	-	87,823	-
Acquisition of generation assets	-	(732,495)	-
Investment in WYCO Development LLC	(2,446)	(8,046)	(42,490)
Change in restricted cash	(95,287)	89	264
Other, net	(6,152)	2,145	(1,917)
Net cash used in investing activities	(2,247,801)	(2,806,724)	(1,734,680)
Financing activities			
(Repayments of) proceeds from short-term borrowings, net	(247,400)	7,400	3,750

Proceeds from issuance of long-term debt	688,598	1,433,406	689,915
Repayments of long-term debt, including reacquisition premiums	(105,623)	(560,383)	(621,296)
Proceeds from issuance of common stock	38,691	457,258	20,133
Redemption of preferred stock	(104,980)	-	-
Dividends paid	(474,760)	(432,110)	(414,922)
Net cash (used in) provided by financing activities	(205,474)	905,571	(322,420)
Net change in cash and cash equivalents	(47,753)	(7,211)	(144,194)
Cash and cash equivalents at beginning of period	108,437	115,648	259,842
Cash and cash equivalents at end of period	$60,684	$108,437	$115,648
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$(531,148)	$(530,072)	$(514,675)
Cash received (paid) for income taxes, net	55,764	(16,635)	21,154
Supplemental disclosure of non-cash investing and financing transactions:			
Property, plant and equipment additions in accounts payable	$137,558	$174,903	$68,417
Storage assets under capital lease	3,688	6,314	71,553
Issuance of common stock for reinvested dividends and 401(k) plans	71,715	63,905	54,638

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

Assets
Current assets
Cash and cash equivalents
Restricted cash
Accounts receivable, net
Accrued unbilled revenues
Inventories
Regulatory assets
Derivative instruments
Deferred income taxes
Prepayments and other
Total current assets
Property, plant and equipment, net
Other assets
Nuclear decommissioning fund and other investments
Regulatory assets
Derivative instruments
Other
Total other assets
Total assets
Liabilities and Equity
Current liabilities
Current portion of long-term debt
Short-term debt
Accounts payable
Regulatory liabilities
Taxes accrued
Accrued interest
Dividends payable
Derivative instruments
Other
Total current liabilities
Deferred credits and other liabilities
Deferred income taxes
Deferred investment tax credits
Regulatory liabilities
Asset retirement obligations
Derivative instruments
Customer advances

Pension and employee benefit obligations
Other
Total deferred credits and other liabilities
Commitments and contingencies
Capitalization
Long-term debt
Preferred stock — 7,000,000 shares authorized of $100 par value; no shares and 1,049,800 shares outstanding at Dec. 31, 2011 2010, respectively
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 486,493,933 and 482,333,750 shares outstanding at Dec and Dec. 31, 2010, respectively
Additional paid in capital
Retained earnings
Accumulated other comprehensive loss
Total common stockholders' equity
Total liabilities and equity

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY
AND COMPREHENSIVE INCOME
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Balance at Dec. 31, 2008	453,792	$ 1,134,480	$ 4,695,019	$ 1,187,911	$ (53,669)	$ 6,963,741
Net income				680,887		680,887
Pension and retiree medical benefit adjustments, net of tax of $(2,203)					(3,129)	(3,129)
Net derivative instrument changes, net of tax of $4,224					6,678	6,678
Unrealized gain - marketable securities, net of tax of $284					411	411
Comprehensive income for 2009						684,847
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(445,356)		(445,356)
Issuances of common stock	3,717	9,293	48,679			57,972
Share-based compensation			26,282			26,282
Balance at Dec. 31, 2009	457,509	$ 1,143,773	$ 4,769,980	$ 1,419,201	$ (49,709)	$ 7,283,245
Net income				755,834		755,834
Pension and retiree medical benefit adjustments, net of tax of $(1,416)					(1,855)	(1,855)
Net derivative instrument changes, net of tax of $(1,208)					(1,659)	(1,659)
Unrealized gain - marketable securities, net of tax of $89					130	130
Comprehensive income for 2010						752,450
Dividends declared:						
Cumulative preferred stock				(4,241)		(4,241)
Common stock				(469,091)		(469,091)
Issuances of common stock	24,825	62,061	426,717			488,778
Share-based compensation			32,378			32,378
Balance at Dec. 31, 2010	482,334	$ 1,205,834	$ 5,229,075	$ 1,701,703	$ (53,093)	$ 8,083,519

Net income				841,172		841,172
Pension and retiree medical benefit adjustments, net of tax of $(2,247)					(3,205)	(3,205)
Net derivative instrument changes, net of tax of $(24,488)					(37,644)	(37,644)
Unrealized loss - marketable securities, net of tax of $(63)					(93)	(93)
Comprehensive income for 2011						800,230
Dividends declared:						
Cumulative preferred stock				(3,534)		(3,534)
Common stock				(503,525)		(503,525)
Premium on redemption of preferred stock				(3,260)		(3,260)
Issuances of common stock	4,160	10,400	54,514			64,914
Share-based compensation			43,854			43,854
Balance at Dec. 31, 2011	486,494	$ 1,216,234	$ 5,327,443	$ 2,032,556	$ (94,035)	$ 8,482,198

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION
(amounts in thousands, except share and per share data)

	Dec. 31 2011	2010
Long-Term Debt		
NSP-Minnesota		
First Mortgage Bonds, Series due:		
Aug. 28, 2012, 8%	$450,000	$450,000
Aug. 15, 2015, 1.95%	250,000	250,000
March 1, 2018, 5.25%	500,000	500,000
March 1, 2019, 8.5% (a)	27,900	27,900
Sept. 1, 2019, 8.5% (a)	100,000	100,000
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
April 1, 2030, 8.5% (a)	69,000	69,000
July 15, 2035, 5.25%	250,000	250,000
June 1, 2036, 6.25%	400,000	400,000
July 1, 2037, 6.2%	350,000	350,000
Nov. 1, 2039, 5.35%	300,000	300,000
Aug. 15, 2040, 4.85%	250,000	250,000
Other	8	32
Unamortized discount	(8,011)	(9,020)
Total	3,338,897	3,337,912
Less current maturities	450,000	19
Total NSP-Minnesota long-term debt	$2,888,897	$3,337,893
PSCo		
First Mortgage Bonds, Series due:		
Oct. 1, 2012, 7.875%	$600,000	$600,000
March 1, 2013, 4.875%	250,000	250,000
April 1, 2014, 5.5%	275,000	275,000
Sept. 1, 2017, 4.375% (a)	129,500	129,500
Aug. 1, 2018, 5.8%	300,000	300,000
Jan. 1, 2019, 5.1% (a)	48,750	48,750
June 1, 2019, 5.125%	400,000	400,000
Nov. 15, 2020, 3.2%	400,000	400,000
Sept. 1, 2037, 6.25%	350,000	350,000
Aug. 1, 2038, 6.5%	300,000	300,000
Aug. 15, 2041, 4.75%	250,000	-
Capital lease obligations, through 2060, 11.2% — 14.3%	191,374	190,223
Unamortized discount	(8,349)	(8,250)
Total	3,486,275	3,235,223
Less current maturities	605,633	6,970
Total PSCo long-term debt	$2,880,642	$3,228,253
SPS		
First Mortgage Bonds, Series due:		

Aug. 15, 2041, 4.5%	$200,000	$-
Unsecured Senior E Notes, due Oct. 1, 2016, 5.6%	200,000	200,000
Unsecured Senior G Notes, due Dec. 1, 2018, 8.75%	250,000	250,000
Unsecured Senior C and D Notes, due Oct. 1, 2033, 6%	100,000	100,000
Unsecured Senior F Notes, due Oct. 1, 2036, 6%	250,000	250,000
Pollution control obligations, securing pollution control revenue bonds, due:		
July 1, 2011, 5.2%	-	44,500
Sept. 1, 2016, 5.75%	-	57,300
Unamortized discount	(6,686)	(4,033)
Total	993,314	897,767
Less current maturities	-	44,500
Total SPS long-term debt	$993,314	$853,267

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CAPITALIZATION — (Continued)
(amounts in thousands, except share and per share data)

	Dec. 31	
	2011	2010
Long-Term Debt — continued		
NSP-Wisconsin		
First Mortgage Bonds, Series due:		
Oct. 1, 2018, 5.25%	$150,000	$150,000
Sept. 1, 2038, 6.375%	200,000	200,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6% (b)	18,600	18,600
Fort McCoy System Acquisition, due Oct. 15, 2030, 7%	625	659
Other	1,892	1,954
Unamortized discount	(1,748)	(1,857)
Total	369,369	369,356
Less current maturities	1,286	1,502
Total NSP-Wisconsin long-term debt	$368,083	$367,854
Other Subsidiaries		
Various Eloigne Co Affordable Housing Project Notes, due 2012-2045, 0% — 9%	$53,728	$61,039
Total	53,728	61,039
Less current maturities	4,974	5,088
Total other subsidiaries long-term debt	$48,754	$55,951
Xcel Energy Inc.		
Unsecured Senior Notes, Series due:		
April 1, 2017, 5.613%	$253,979	$253,979
May 15, 2020, 4.7%	550,000	550,000
July 1, 2036, 6.5%	300,000	300,000
Sept. 15, 2041, 4.8%	250,000	-
Junior Subordinated Notes, Series due:		
Jan. 1, 2068, 7.6%	400,000	400,000
Elimination of PSCo capital lease obligation with affiliates	(76,329)	(74,937)
Unamortized discount	(10,798)	(11,780)
Total	1,666,852	1,417,262
Less current maturities (including elimination of PSCo capital lease obligation)	(1,971)	(2,664)
Total Xcel Energy Inc. long-term debt	$1,668,823	$1,419,926
Total long-term debt	$8,848,513	$9,263,144
Preferred Stockholders' Equity		
Preferred stock — 7,000,000 shares authorized of $100 par value; no shares and 1,049,800 shares outstanding at Dec. 31, 2011 and 2010, respectively		
$3.60 series, 275,000 shares	$-	$27,500
$4.08 series, 150,000 shares	-	15,000
$4.10 series, 175,000 shares	-	17,500
$4.11 series, 200,000 shares	-	20,000
$4.16 series, 99,800 shares	-	9,980
$4.56 series, 150,000 shares	-	15,000

Total preferred stockholders' equity	$ -	$ 104,980
Common Stockholders' Equity		
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 486,493,933 and 482,333,750 shares outstanding at Dec. 31, 2011 and 2010, respectively	$ 1,216,234	$ 1,205,834
Additional paid in capital	5,327,443	5,229,075
Retained earnings	2,032,556	1,701,703
Accumulated other comprehensive loss	(94,035)	(53,093)
Total common stockholders' equity	$ 8,482,198	$ 8,083,519

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

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Business and System of Accounts — Xcel Energy Inc.'s utility subsidiaries are principally engaged in the regulated generation, purchase, transmission, distribution and sale of electricity and in the regulated purchase, transportation, distribution and sale of natural gas. Xcel Energy's consolidated financial statements and disclosures are presented in accordance with GAAP. All of the utility subsidiaries' underlying accounting records also 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 2011, Xcel Energy's operations included the activity of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utility subsidiaries serve electric and natural gas customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Also included in Xcel Energy's operations are WGI, an interstate natural gas pipeline company, and WYCO, a joint venture with CIG to develop and lease natural gas pipelines, storage and compression facilities.

Xcel Energy Inc.'s nonregulated subsidiary is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits. Xcel Energy Inc. owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group, Inc., Xcel Energy International Inc., and Xcel Energy Services Inc. Xcel Energy Inc. and its subsidiaries collectively are referred to as Xcel Energy.

Xcel Energy's consolidated financial statements include its wholly-owned subsidiaries and variable interest entities for which it is the primary beneficiary. In the consolidation process, all intercompany transactions and balances are eliminated. Xcel Energy uses the equity method of accounting for its investments in WYCO. Xcel Energy's equity earnings in WYCO are included on the consolidated statements of income as equity earnings of unconsolidated subsidiaries. Xcel Energy has investments in several plants and transmission facilities jointly owned with nonaffiliated utilities. Xcel Energy's proportionate share of jointly owned facilities is recorded as property, plant and equipment on the consolidated balance sheets, and Xcel Energy's proportionate share of the operating costs associated with these facilities is included in its consolidated statements of income. See Note 5 for further discussion of jointly owned generation, transmission, and gas facilities and related ownership percentages.

Xcel Energy evaluates its arrangements and contracts with other entities, including but not limited to, investments, purchased power agreements and fuel contracts to determine if the other party is a variable interest entity and if so, if Xcel Energy is the primary beneficiary. Xcel Energy follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether Xcel Energy is a variable interest entity's primary beneficiary. See Note 13 for further discussion of variable interest entities.

Use of Estimates — In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. Estimates are used for such items as plant depreciable lives, AROs, decommissioning, regulatory assets and liabilities, 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.

Regulatory Accounting — Our regulated utility subsidiaries account for certain income and expense items in accordance with accounting guidance for regulated operations. Under this guidance:

- Certain costs, which would otherwise be charged to expense or OCI, are deferred as regulatory assets based on the expected ability to recover the costs in future rates; and
- Certain credits, which would otherwise be reflected as income, are deferred as regulatory liabilities based on the expectation the amounts will be returned to customers in future rates, or because the amounts were collected in rates prior to the costs being incurred.

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 treatment in the rate setting process.

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If restructuring or other changes in the regulatory environment occur, regulated utility subsidiaries may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from their balance sheets. Such changes could have a material effect on Xcel Energy's financial condition, results of operations and cash flows in the period the write-offs are recorded. See Note 15 for further discussion of regulatory assets and liabilities.

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 recognized. Xcel Energy presents its revenues net of any excise or other fiduciary-type taxes or fees.

NSP-Minnesota participates in MISO, and SPS participates in SPP. The revenues and charges from these RTOs related to serving retail and wholesale electric customers comprising the native load of NSP-Minnesota and SPS are recorded on a net basis within cost of sales. Revenues and charges for short term wholesale sales of excess energy transacted through RTOs are recorded on a gross basis in electric revenues and cost of sales.

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

Conservation Programs — Xcel Energy Inc.'s utility subsidiaries have implemented programs in many of their retail jurisdictions to assist customers in conserving energy and reducing peak demand on the electric and natural gas systems. These programs include, but are not limited to, efficiency and redesign programs and rebates for the purchase of items such as compact fluorescent bulbs, saver switches and energy-efficient heating and cooling appliances.

The costs incurred for DSM and CIP programs are deferred if it is probable that future revenue, in an amount at least equal to the deferred amount, will be provided to permit recovery of the previously incurred cost, rather than to provide for expected future amounts of similar programs. For incentive programs designed to allow adjustments of future rates for recovery of lost margins and/or conservation performance incentives, recorded revenues are limited to those amounts expected to be collected within 24 months following the end of the annual period in which they are earned.

For PSCo, SPS and NSP-Minnesota, DSM and CIP program costs are recovered through a combination of base rate revenue and rider mechanisms. The revenue billed to customers recovers incurred costs for conservation programs and also incentive amounts that are designed to encourage Xcel Energy's achievement of energy conservation goals and compensate for related lost sales margin. For these utility subsidiaries, regulatory assets are recognized to reflect the amount of costs or earned incentives that have not yet been collected from customers. NSP-Wisconsin recovers approved conservation program costs in base rate revenue, without the use of rider mechanisms.

Property, Plant and Equipment and Depreciation — Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired is charged to accumulated depreciation and amortization. Amounts recovered in rates for future removal costs are recorded as regulatory liabilities. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance costs are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses as incurred. Planned major maintenance activities are charged to operating expense unless the cost represents the acquisition of an additional unit of property or the replacement of an existing unit of property. Property, plant and equipment also includes costs associated with property held for future use. The depreciable lives of certain plant assets are reviewed annually and revised, if appropriate. Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. Upon regulatory approval of deferred accounting for accelerated depreciation expenses, property, plant and equipment that is to be early decommissioned is reclassified as plant to be retired.

Xcel Energy records depreciation expense related to its plant using the straight-line method over the plant’s useful life. Actuarial and semi-actuarial life studies are performed on a periodic basis and submitted to the state and federal commissions for review. Upon acceptance by the various commissions, the resulting lives and net salvage rates are used to calculate depreciation. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 2.9, 3.0, and 2.9 percent for the years ended Dec. 31, 2011, 2010 and 2009, respectively.

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Leases — Xcel Energy evaluates a variety of contracts for lease classification at inception, including purchased power agreements and rental arrangements for office space, vehicles and equipment. Contracts determined to contain a lease because of per unit pricing that is other than fixed or market price, terms regarding the use of a particular asset, and other factors are evaluated further to determine if the arrangement is a capital lease. See Note 13 for further discussion of leases.

AFUDC — AFUDC represents the cost of capital used to finance utility construction activity. AFUDC is computed by applying a composite pretax rate to qualified CWIP. The amount of AFUDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFUDC amounts capitalized are included in Xcel Energy's rate base for establishing utility service rates. In addition to construction-related amounts, cost of capital also is recorded to reflect returns on capital used to finance conservation programs in Minnesota.

Generally, AFUDC costs are recovered from customers as the related property is depreciated. However, in some cases commissions have approved a more current recovery of cost associated with large capital projects, resulting in a lower recognition of AFUDC. In other cases, some commissions have allowed an AFUDC calculation greater than the FERC-defined AFUDC rate, resulting in higher recognition of AFUDC.

Asset Retirement Obligations — Xcel Energy Inc.'s utility subsidiaries account for AROs under accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a long-lived asset. The liability is generally increased over time by applying the interest method of accretion, and the capitalized costs are depreciated over the useful life of the long-lived asset. Changes resulting from revisions to the timing or amount of expected asset retirement cash flows are recognized as an increase or a decrease in the ARO. Xcel Energy Inc.'s utility subsidiaries also recover through rates certain future plant removal costs in addition to asset retirement obligations and related capitalized costs. The accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability. See Note 13 for further discussion of asset retirement obligations.

Nuclear Decommissioning — Nuclear decommissioning studies estimate NSP-Minnesota's ultimate costs of decommissioning its nuclear power plants and are performed at least every three years and submitted to the MPUC for approval. NSP-Minnesota filed its most recent triennial nuclear decommissioning studies with the MPUC in December 2011. These studies reflect NSP-Minnesota's plans, under the current operating licenses, for prompt dismantlement of the Monticello and Prairie Island facilities. These studies assume that NSP-Minnesota will be storing spent fuel on site pending removal to a U.S. government facility.

For rate making purposes, NSP-Minnesota recovers the total decommissioning costs related to its nuclear power plants, including operating costs associated with spent fuel, over each facility's expected service life based on the triennial decommissioning studies filed with the MPUC. The costs are initially determined in nominal amounts prior to escalation adjustments, then future periods' costs are escalated using decommissioning-specific cost escalators and finally discounted using risk-free interest rates. See Note 14 for further discussion of the approved nuclear decommissioning obligation.

For financial reporting purposes, NSP-Minnesota recognizes decommissioning liabilities, excluding future operating costs associated with spent fuel, in accordance with accounting guidance that requires a liability for the fair value of an ARO to be recognized in the period in which it is incurred. In accordance with regulatory accounting, any difference between expense recognized for financial reporting purposes and the amount recovered in rates is reported as a regulatory asset or liability. Costs are initially determined in nominal amounts prior to escalation adjustments, then future periods' costs are escalated using decommissioning-specific cost escalators and then discounted using weighted-average credit-adjusted risk-free interest rates.

Restricted funds for the payment of future decommissioning expenditures for NSP-Minnesota's nuclear facilities are included in the nuclear decommissioning fund on the consolidated balance sheets. See Note 11 for further discussion of the nuclear decommissioning fund.

Nuclear Fuel Expense — Nuclear fuel expense, which is recorded as NSP-Minnesota's nuclear generating plants use fuel, includes the cost of fuel used in the current period (including AFUDC), as well as future disposal costs of spent nuclear fuel and costs associated with the end-of-life fuel segments.

Nuclear Refueling Outage Costs — Xcel Energy uses a deferral and amortization method for nuclear refueling O&M costs. This method amortizes refueling outage costs over the period between refueling outages consistent with how the costs are recovered ratably in electric rates.

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

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

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, the reversal of some temporary differences are accounted for as current income tax expense. Investment tax credits are deferred and their benefits amortized over the book depreciable lives of the related property. Utility rate regulation also has resulted in the recognition of certain regulatory assets and liabilities related to income taxes, which are summarized in Note 15.

Xcel Energy follows the applicable accounting guidance to measure and disclose uncertain tax positions that it has taken or expects to take in its income tax returns. Xcel Energy recognizes a tax position in its consolidated financial statements when it is more likely than not that the position will be sustained upon examination based on the technical merits of the position. Recognition of changes in uncertain tax positions are reflected as a component of income tax.

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

Xcel Energy Inc. and its subsidiaries file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal income taxes paid by Xcel Energy Inc., as parent of the Xcel Energy consolidated group, are allocated to Xcel Energy Inc.'s subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy Inc. in connection with combined state filings. Xcel Energy Inc. also allocates its own income tax benefits to its direct subsidiaries based on the relative positive tax liabilities of the subsidiaries.

See Note 6 for further discussion of income taxes.

Types of and Accounting for Derivative Instruments — Xcel Energy uses derivative instruments in connection with its interest rate, utility commodity price, vehicle fuel price, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. All derivative instruments not designated and qualifying for the normal purchases and normal sales exception, as defined by the accounting guidance for derivatives and hedging, are recorded on the consolidated balance sheets at fair value as derivative instruments. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The classification of changes in fair value for those derivative instruments is dependent on the designation of a qualifying hedging relationship. Changes in fair value of derivative instruments not designated in a qualifying hedging relationship are reflected in current earnings or as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms.

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

Cash Flow Hedges — Certain qualifying hedging relationships are designated as a hedge of a forecasted transaction, or future cash flow (cash flow hedge). Changes in the fair value of a derivative designated as a cash flow hedge, to the extent effective, are included in OCI, or deferred as a regulatory asset or liability based on recovery mechanisms until earnings are affected by the hedged transaction.

Normal Purchases and Normal Sales — Xcel Energy enters into contracts for the purchase and sale of commodities for use in its business operations. Derivatives and hedging accounting guidance requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from derivative accounting as normal purchases or normal sales.

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Xcel Energy evaluates all of its contracts at inception to determine if they are derivatives and if they meet the normal purchases and normal sales designation requirements. None of the contracts entered into within the commodity trading operations qualify for a normal purchases and normal sales designation.

See Note 11 for further discussion of Xcel Energy's risk management and derivative activities.

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 electric operating revenues in the consolidated statements of income.

Xcel Energy's commodity trading operations are conducted by NSP-Minnesota, PSCo and SPS. Commodity trading activities are not associated with energy produced from Xcel Energy's generation assets or energy and capacity purchased to serve native load. Commodity trading contracts are recorded at fair market value and commodity trading results include the impact of all margin-sharing mechanisms. See Note 11 for further discussion.

Fair Value Measurements — Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest; money market funds are measured using quoted net asset values. For interest rate derivatives, quoted prices based primarily on observable market interest rate curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are generally used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models, generally using the most observable inputs available, are utilized to estimate fair value for each class of security. See Note 11 for further discussion.

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

Accounts Receivable and Allowance for Bad Debts — Accounts receivable are stated at the actual billed amount net of an allowance for bad debts. Xcel Energy establishes an allowance for uncollectible receivables based on a policy that reflects its expected exposure to the credit risk of customers.

Inventory — All inventory is recorded at average cost.

Renewable Energy Credits — RECs are marketable environmental commodities that represent proof that energy was generated from eligible renewable energy sources. RECs are awarded upon delivery of the associated energy and can be bought and sold. RECs are typically used as a form of measurement of compliance to RPS enacted by those states that are encouraging construction and consumption from renewable energy sources, but can also be sold separately from the energy produced. Currently, utility subsidiaries acquire RECs from the generation or purchase of renewable power.

When RECs are acquired in the course of generation or purchased as a result of meeting load obligations, they are recorded as inventory at cost. The cost of RECs that are utilized for compliance purposes is recorded as electric fuel and purchased power expense. As a result of state regulatory orders, Xcel Energy reduces recoverable fuel costs for the value of certain RECs and records the cost of future compliance requirements that are recoverable in future rates as regulatory assets.

Sales of RECs that are acquired in the course of generation or purchased as a result of meeting load obligations are recorded in electric utility operating revenues on a gross basis. The cost of these RECs, related transaction costs, and amounts credited to customers under margin-sharing mechanisms are recorded in electric fuel and purchased power expense. RECs acquired for trading purposes are recorded as other investments and are also recorded at cost. The sales of RECs for trading purposes are recorded in electric utility operating revenues, net of the cost of the RECs, transaction costs, and amounts credited to customers under margin-sharing mechanisms.

Emission Allowances — Emission allowances, including the annual SO_2 and NO_x emission allowance entitlement received at no cost from the EPA, are recorded at cost plus associated broker commission fees. Xcel Energy follows the inventory accounting model for all emission allowances. The sales of emission allowances are included in electric utility operating revenues and the operating activities section of the consolidated statements of cash flows.

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

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 remediation proceeds. If other participating PRPs exist and acknowledge their potential involvement with a site, costs are estimated and recorded only for Xcel Energy's expected share of the cost. Any future costs of restoring sites where operation may extend indefinitely are treated as a capitalized cost of plant retirement. The depreciation expense levels recoverable in rates include a provision for removal expenses, which may include final remediation costs. Removal costs recovered in rates are classified as a regulatory liability.

See Note 13 for further discussion of environmental costs.

Benefit Plans and Other Postretirement Benefits — Xcel Energy maintains pension and postretirement benefit plans for eligible employees. Recognizing the cost of providing benefits and measuring the projected benefit obligation of these plans under applicable accounting guidance requires management to make various assumptions and estimates.

Based on the regulatory recovery mechanisms of Xcel Energy Inc.'s utility subsidiaries, certain unrecognized actuarial gains and losses and unrecognized prior service costs or credits are recorded as regulatory assets and liabilities, rather than OCI.

See Note 9 for further discussion of benefit plans and other postretirement benefits.

Guarantees — Xcel Energy recognizes, upon issuance or modification of a guarantee, a liability for the fair market value of the obligation that has been assumed in issuing the guarantee. This liability includes consideration of specific triggering events and other conditions which may modify the ongoing obligation to perform under the guarantee.

The obligation recognized is reduced over the term of the guarantee as Xcel Energy is released from risk under the guarantee. See Note 13 for specific details of issued guarantees.

Subsequent Events — Management has evaluated the impact of events occurring after Dec. 31, 2011 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

2. Accounting Pronouncements

Recently Adopted

Multiemployer Plans — In September 2011, the FASB issued Multiemployer Plans (Subtopic 715-80) — Disclosures about an Employer's Participation in a Multiemployer Plan (ASU No. 2011-09), which updates the Codification to require certain disclosures about an entity's involvement with multiemployer pension and other postretirement benefit plans. These updates do not affect recognition and measurement guidance for an employer's participation in multiemployer plans, but rather require additional disclosure such as the nature of multiemployer plans and the employer's participation, contributions to the plans and details regarding any significant plans. These updates to the Codification are effective for annual periods ending after Dec. 15, 2011. Xcel Energy implemented the annual disclosure guidance effective Jan. 1, 2011, and the implementation did not have a material impact on its consolidated financial statements. For further information and required disclosures, see Note 9.

Recently Issued

Fair Value Measurement — In May 2011, the FASB issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU No. 2011-04), which provides additional guidance for fair value measurements. These updates to the Codification include clarifications regarding existing fair value measurement principles and disclosure requirements, and also specific new guidance for items such as measurement of instruments classified within stockholders' equity. These updates to the Codification are effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy does not expect the implementation of this guidance to have a material impact on its consolidated financial statements.

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Comprehensive Income — In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05), which updates the Codification to require the presentation of the components of net income, the components of OCI and total comprehensive income in either a single continuous statement of comprehensive income or in two separate, but consecutive statements of net income and comprehensive income. These updates do not affect the items reported in OCI or the guidance for reclassifying such items to net income. These updates to the Codification are effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy does not expect the implementation of this presentation guidance to have a material impact on its consolidated financial statements.

Balance Sheet Offsetting — In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which updates the Codification to require disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. These updates to the disclosure requirements of the Codification do not affect the presentation of amounts in the consolidated balance sheets, and are effective for annual reporting periods beginning on or after Jan. 1, 2013, and interim periods within those periods. Xcel Energy does not expect the implementation of this disclosure guidance to have a material impact on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Dec. 31, 2011	Dec. 31, 2010
Accounts receivable, net		
Accounts receivable	$ 811,685	$ 773,037
Less allowance for bad debts	(58,565)	(54,563)
	$ 753,120	$ 718,474
Inventories		
Materials and supplies	$ 202,699	$ 196,081
Fuel	236,023	188,566
Natural gas	179,510	176,153
	$ 618,232	$ 560,800
Property, plant and equipment, net		
Electric plant	$ 27,254,541	$ 24,993,582
Natural gas plant	3,676,754	3,463,343
Common and other property	1,546,643	1,555,287
Plant to be retired (a)	151,184	236,606
Construction work in progress	1,085,245	1,186,433
Total property, plant and equipment	33,714,367	31,435,251
Less accumulated depreciation	(11,658,351)	(11,068,820)
Nuclear fuel	1,939,299	1,837,697
Less accumulated amortization	(1,641,948)	(1,541,046)
	$ 22,353,367	$ 20,663,082

(a) In 2010, in response to the CACJA, the CPUC approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. Amounts are presented net of accumulated depreciation. See Item 1 – Public Utility Regulation for further discussion.

4. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated upon consolidation.

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Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450
Amount outstanding at period end	219
Average amount outstanding	165
Maximum amount outstanding	241
Weighted average interest rate, computed on a daily basis	0.35%
Weighted average interest rate at end of period	0.40

(Amounts in Millions, Except Interest Rates)	Twelve Months Ended Dec. 31, 2011	Twelve Months Ended Dec. 31, 2010	Twelve Months Ended Dec. 31, 2009
Borrowing limit	$ 2,450	$ 2,177	$ 2,177
Amount outstanding at period end	219	466	459
Average amount outstanding	430	263	406
Maximum amount outstanding	824	653	675
Weighted average interest rate, computed on a daily basis	0.36%	0.36%	0.95%
Weighted average interest rate at end of period	0.40	0.40	0.36

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit agreements.

During 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new four-year credit agreements. The total size of the credit facilities is $2.45 billion and each credit facility terminates in March 2015. Xcel Energy Inc. and its utility subsidiaries have the right to request an extension of the revolving termination date for two additional one-year periods, subject to majority bank group approval.

The credit facilities provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings. Other features of the credit facilities include:

- Each of the credit facilities, other than NSP-Wisconsin’s, may be increased by up to $200 million for Xcel Energy Inc., $100 million each for NSP-Minnesota and PSCo, and $50 million for SPS.
- Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at Dec. 31, 2011 as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
Xcel Energy	55	%
NSP-Wisconsin	50	

NSP-Minnesota	48
SPS	48
PSCo	45

If Xcel Energy Inc. or any of its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.

- The Xcel Energy Inc. credit facility has a cross-default provision that provides Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries, except NSP-Wisconsin as long as its total assets do not comprise more than 15 percent of Xcel Energy’s consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding $75 million.

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- The interest rates under these lines of credit are based on the Eurodollar rate or an alternate base rate, plus a borrowing margin of 0 to 200 basis points per year based on the applicable credit ratings.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 10 to 35 basis points per year.
  - NSP-Wisconsin's intercompany borrowing arrangement with NSP-Minnesota was subsequently terminated.

At Dec. 31, 2011, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Facility	Drawn (a)	Available
Xcel Energy Inc.	$ 800.0	$ 127.1	$ 672.9
PSCo	700.0	4.9	695.1
NSP-Minnesota	500.0	33.7	466.3
SPS	300.0	-	300.0
NSP-Wisconsin	150.0	66.0	84.0
Total	$ 2,450.0	$ 231.7	$ 2,218.3

(a)Includes outstanding commercial paper and letters of credit.

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Dec. 31, 2011 and 2010.

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Dec. 31, 2011 and 2010, there were $12.7 million and $10.1 million of letters of credit outstanding, respectively, under the credit facilities. An additional $1.1 million of letters of credit not issued under the credit facilities were outstanding at Dec. 31, 2011 and 2010, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

Long-Term Borrowings and Other Financing Instruments

Generally, all real and personal property of NSP-Minnesota and NSP-Wisconsin and all real and personal property used in or in connection with the electric utility business of PSCo and SPS are subject to the liens of their first mortgage indentures. Additionally, debt premiums, discounts and expenses are amortized over the life of the related debt. The premiums, discounts and expenses associated with refinanced debt are deferred and amortized over the life of the related new issuance, in accordance with regulatory guidelines.

Maturities of long-term debt are as follows:

(Millions of Dollars)	
2012	$ 1,060
2013	257
2014	282
2015	256
2016	207

Xcel Energy has entered into a Replacement Capital Covenant (RCC). Under the terms of the RCC, Xcel Energy has agreed not to redeem or repurchase all or part of the $400 million of 7.6 percent junior subordinated notes due 2068 (Junior Subordinated Notes) prior to 2038 unless qualifying securities are issued to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Subordinated Notes at the time of redemption or repurchase.

During 2011, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In September 2011, Xcel Energy Inc. issued $250 million of 4.80 percent senior unsecured notes due Sept. 15, 2041.
- In August 2011, PSCo issued $250 million of 4.75 percent first mortgage bonds due Aug. 15, 2041.
- In August 2011, SPS issued $200 million of 4.50 percent first mortgage bonds due Aug. 15, 2041.

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During 2010, Xcel Energy Inc. and its utility subsidiaries completed the following financings:

- In May 2010, Xcel Energy Inc. issued $550 million of 4.70 percent unsecured senior notes, due May 15, 2020.
- In August 2010, NSP-Minnesota issued $250 million of 1.95 percent first mortgage bonds, due Aug. 15, 2015 and $250 million of 4.85 percent first mortgage bonds, due Aug. 15, 2040.
- In November 2010, PSCo issued $400 million of 3.2 percent first mortgage bonds, due Nov. 15, 2020.

Deferred Financing Costs — Other assets included deferred financing costs of approximately $75 million and $74 million, net of amortization, at Dec. 31, 2011 and 2010, respectively. Xcel Energy is amortizing these financing costs over the remaining maturity periods of the related debt.

Capital Stock — Xcel Energy Inc. has authorized 7,000,000 shares of preferred stock with a $100 par value. At Dec. 31, 2011, there were no shares of preferred stock outstanding and at Dec. 31, 2010, Xcel Energy Inc. had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102 to $103.75 per share plus accrued dividends. Xcel Energy Inc. redeemed all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions of Xcel Energy's earnings available to common shareholders in the consolidated statements of income.

The charters of some of Xcel Energy Inc.'s subsidiaries also authorize the issuance of preferred stock. However, at Dec. 31, 2011 and 2010, there were no preferred shares of subsidiaries outstanding. The following table lists preferred shares by subsidiary at Dec. 31, 2011 and 2010:

	Preferred Shares Authorized	Par Value
SPS	10,000,000	$ 1.00
PSCo	10,000,000	0.01

Xcel Energy Inc. has authorized 1,000,000,000 shares of common stock. Outstanding shares at Dec. 31, 2011 and 2010 were 486,493,933 and 482,333,750, respectively.

Dividend and Other Capital-Related Restrictions — Xcel Energy Inc.'s Articles of Incorporation place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there was no preferred stock outstanding at Dec. 31, 2011, the restrictions did not place any effective limit on Xcel Energy Inc.'s ability to pay dividends at Dec. 31, 2011.

All of Xcel Energy's utility subsidiaries' dividends are subject to the FERC's jurisdiction under the Federal Power Act, which prohibits the payment of dividends out of capital accounts; payment of dividends is allowed out of retained earnings only.

NSP-Minnesota's first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy Inc., the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $1.1 billion in additional cash dividends on common stock at Dec. 31, 2010, or $1.2 billion at Dec. 31, 2011.

NSP-Minnesota's state regulatory commissions indirectly limit the amount of dividends NSP-Minnesota can pay to Xcel Energy Inc. by requiring an equity-to-total capitalization ratio between 47.07 percent and 57.53 percent. NSP-Minnesota's equity-to-total capitalization ratio was 52.1 percent at Dec. 31, 2011. Total capitalization for NSP-Minnesota cannot exceed $8.25 billion.

NSP-Wisconsin shall not pay dividends if its calendar year average equity-to-total capitalization ratio is or falls below the state commission authorized level of 52.5 percent. NSP-Wisconsin's calendar year average equity-to-total capitalization ratio was 55.1 percent at Dec. 31, 2011.

SPS' state regulatory commissions indirectly limit the amount of dividends that SPS can pay Xcel Energy Inc. by requiring an equity-to-total capitalization ratio (excluding short-term debt) between 45.0 percent and 55.0 percent. In addition, SPS may not pay a dividend that would cause it to lose its investment grade bond rating. SPS' equity-to-total capitalization ratio (excluding short-term debt) was 52.0 percent at Dec. 31, 2011.

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

- PSCo currently has authorization to issue up to $1.15 billion of long-term debt and up to $800 million of short-term debt.
- SPS currently has authorization to issue up $400 million of short-term debt.
- NSP-Wisconsin currently has authorization to issue up to $150 million of long-term debt and up to $150 million of short-term debt.
- NSP-Minnesota has authorization to issue long-term securities provided the equity-to-total capitalization ratio remains between 47.07 percent and 57.53 percent and to issue short-term debt provided it does not exceed 15 percent of total capitalization. Total capitalization for NSP-Minnesota cannot exceed $8.25 billion.

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

5. Joint Ownership of Generation, Transmission and Gas Facilities

Following are the investments by Xcel Energy Inc.'s utility subsidiaries in jointly owned generation, transmission and gas facilities and the related ownership percentages as of Dec. 31, 2011:

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %	
NSP-Minnesota					
Electric Generation:					
Sherco Unit 3	$565,832	$ 358,907	$ 3,731	59.0	%
Sherco Common Facilities Units 1, 2 and 3	138,790	82,229	531	80.0	
Sherco Substation	4,790	2,621	-	59.0	
Electric Transmission:					
Grand Meadow Line and Substation	11,204	855	-	50.0	
CapX2020 Transmission	57,856	8,899	74,404	49.6	
Total NSP-Minnesota	$778,472	$ 453,511	$ 78,666		

(Thousands of Dollars)	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %	
PSCo					
Electric Generation:					
Hayden Unit 1	$88,337	$ 60,549	$ 830	75.5	%
Hayden Unit 2	119,621	55,126	722	37.4	
Hayden Common Facilities	34,558	14,155	1	53.1	
Craig Units 1 and 2	54,058	33,225	193	9.7	
Craig Common Facilities 1, 2 and 3	35,241	15,896	2,863	6.5 - 9.7	
Comanche Unit 3	867,976	28,973	1,014	66.7	
Comanche Common Facilities	12,628	219	169	82.0	

Electric Transmission:				
Transmission and other facilities, including substations	150,420	56,654	449	Various
Gas Transportation:				
Rifle to Avon	16,278	6,333	-	60.0
Total PSCo	$1,379,117	$ 271,130	$ 6,241	

NSP-Minnesota and PSCo have approximately 500 MW and 820 MW of jointly owned generating capacity, respectively. NSP-Minnesota's and PSCo's share of operating expenses and construction expenditures are included in the applicable utility accounts. Each of the respective owners is responsible for providing its own financing.

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NSP-Minnesota is part owner of Sherco Unit 3, an 860 MW, coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. In November 2011, Sherco Unit 3 experienced a significant failure of its turbine, generator, and exciter systems. The facility was immediately shut down and isolated for investigation of the cause of the failure, which is still uncertain. It is unknown when Sherco Unit 3 will recommence operations. NSP-Minnesota maintains insurance policies for the entire unit, inclusive of the other joint owner's proportionate share. Replacement and repair of damaged systems, and other significant costs of the failure in excess of a $1.5 million deductible are expected to be recovered through these insurance policies. For its proportionate share of possible expenditures in excess of insurance recoveries for components of the jointly owned facility, NSP-Minnesota will recognize additions to property, plant and equipment and O&M. Sherco Units 1 and 2, wholly owned by NSP-Minnesota, continue to operate.

6. Income Taxes

COLI — In 2007, Xcel Energy Inc., PSCo and the U.S. government settled an ongoing dispute regarding PSCo's right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by PSRI. Xcel Energy Inc. and PSCo paid the U.S. government a total of $64.4 million in settlement of the U.S. government's claims for tax, penalty and interest for tax years 1993 through 2007. Xcel Energy Inc. and PSCo surrendered the policies to its insurer on Oct. 31, 2007, without recognizing a taxable gain. As a result of the settlement, the lawsuit filed by Xcel Energy Inc. and PSCo in the U.S. District Court was dismissed and the Tax Court proceedings were dismissed in December 2010 and January 2011.

As part of the Tax Court proceedings, during 2010, an agreement in principle of Xcel Energy Inc.'s and PSCo's statements of account was reached, dating back to tax year 1993. Upon completion of this review, PSRI recorded a net non-recurring tax and interest charge of approximately $9.4 million. Upon final cash settlement in 2011, Xcel Energy received $0.7 million and recognized a further reduction of expense of $0.3 million. A closing agreement covering tax years 2003 through 2007 was finalized with the IRS in January 2012.

In 2010, Xcel Energy Inc., PSCo and PSRI entered into a settlement agreement with Provident related to all claims asserted by Xcel Energy Inc., PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI program. Under the terms of the settlement, Xcel Energy Inc., PSCo and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company in 2010. The $25 million proceeds were not subject to income taxes.

Medicare Part D Subsidy Reimbursements — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Based on this provision, Xcel Energy became subject to additional taxes and was required to reverse previously recorded tax benefits in the period of enactment. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. Xcel Energy does not expect the $17 million of additional tax expense to recur in future periods.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expired in September 2011. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expires in September 2012. The IRS commenced an examination of tax years 2008 and 2009 in the third quarter of 2010. In December 2011, Xcel Energy finalized the Revenue Agent Report and signed the Waiver of Assessment for tax years 2008 and 2009. The total assessment for these tax years was $1.4 million, including tax and interest.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of Dec. 31, 2011, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2006
Minnesota	2007
Texas	2007
Wisconsin	2007

As of Dec. 31, 2011, there were no state income tax audits in progress.

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Unrecognized Tax Benefits —The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual ETR. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Dec. 31, 2011	Dec. 31, 2010
Unrecognized tax benefit - Permanent tax positions	$ 4.3	$ 5.9
Unrecognized tax benefit - Temporary tax positions	30.4	34.6
Unrecognized tax benefit balance	$ 34.7	$ 40.5

A reconciliation of the beginning and ending amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	2011	2010	2009
Balance at Jan. 1	$40.5	$30.3	$42.1
Additions based on tax positions related to the current year - continuing operations	11.9	13.4	12.6
Reductions based on tax positions related to the current year - continuing operations	(1.9)	(0.6)	(1.8)
Additions for tax positions of prior years - continuing operations	14.0	5.5	6.8
Reductions for tax positions of prior years - continuing operations	(2.4)	(1.8)	(2.3)
Reductions for tax positions of prior years - discontinued operations	-	(6.3)	-
Settlements with taxing authorities - continuing operations	(27.3)	-	(27.1)
Lapse of applicable statutes of limitations - continuing operations	(0.1)	-	-
Balance at Dec. 31	$34.7	$40.5	$30.3

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryfowards are as follows:

(Millions of Dollars)	Dec. 31, 2011	Dec. 31, 2010
NOL and tax credit carryforwards	$ (33.6)	$ (38.0)

The decrease in the unrecognized tax benefit balance of $5.8 million in 2011 was due to the resolution of certain federal audit matters, partially offset by an increase due to the addition of uncertain tax positions related to current and prior years' activity. Xcel Energy's amount of unrecognized tax benefits could change in the next 12 months as the IRS and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change. However, Xcel Energy does not anticipate total unrecognized tax benefits will significantly change within the next 12 months.

The payable for interest related to unrecognized tax benefits is substantially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits reported is as follows:

(Millions of Dollars)	2011	2010	2009
Payable for interest related to unrecognized tax benefits at Jan. 1	$(0.3)	$(0.2)	$(0.4)
Interest income (expense) related to unrecognized tax benefits - continuing operations	0.9	(0.6)	1.5

Interest (expense) income related to unrecognized tax benefits - discontinued operations	(0.8)	0.5	(1.3)
Payable for interest related to unrecognized tax benefits at Dec. 31	$(0.2)	$(0.3)	$(0.2)

No amounts were accrued for penalties related to unrecognized tax benefits as of Dec. 31, 2011, 2010 or 2009.

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Other Income Tax Matters — NOL amounts represent the amount of the tax loss that is carried forward and tax credits represent the deferred tax asset. NOL and tax credit carryforwards as of Dec. 31 were as follows:

(Millions of Dollars)	2011	2010
Federal NOL carryforward	$1,710	$989
Federal tax credit carryforwards	232	205
State NOL carryforwards	1,707	1,363
Valuation allowances for state NOL carryforwards	(51)	(32)
State tax credit carryforwards, net of federal detriment (a)	22	21
Valuation allowances for state tax credit carryforwards, net of federal benefit	(2)	-

(a) State tax credit carryforwards are net of federal detriment of $12 million and $11 million as of Dec. 31, 2011 and 2010, respectively.

The federal carryforward periods expire between 2021 and 2031. The state carryforward periods expire between 2012 and 2031.

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 reconciles such differences for the years ending Dec. 31:

	2011	2010	2009
Federal statutory rate	35.0 %	35.0 %	35.0 %
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.2	3.9	4.0
Resolution of income tax audits and other	0.3	0.6	0.8
Tax credits recognized, net of federal income tax expense	(2.6)	(1.8)	(2.0)
Regulatory differences — utility plant items	(0.8)	(1.1)	(2.0)
Change in unrecognized tax benefits	(0.1)	0.1	(0.5)
Life insurance policies	(0.1)	(0.8)	(0.2)
Previously recognized Medicare Part D subsidies	-	1.4	-
Other, net	(0.1)	(0.6)	-
Effective income tax rate from continuing operations	35.8 %	36.7 %	35.1 %

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

(Thousands of Dollars)	2011	2010	2009
Current federal tax expense (benefit)	$3,399	$16,657	$(39,886)
Current state tax expense	9,971	12,580	8,672
Current change in unrecognized tax benefit	(8,266)	(2,982)	(7,627)
Current tax credits	-	(944)	-
Deferred federal tax expense	410,794	376,073	360,252
Deferred state tax expense	80,670	52,543	69,947
Deferred change in unrecognized tax expense	6,705	4,641	2,387
Deferred tax credits	(28,763)	(15,580)	(16,005)
Deferred investment tax credits	(6,194)	(6,353)	(6,426)
Total income tax expense from continuing operations	$468,316	$436,635	$371,314

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

(Thousands of Dollars)	2011	2010
Deferred tax liabilities:		
Differences between book and tax bases of property	$4,558,951	$3,853,425
Regulatory assets	253,162	242,760
Other	279,162	219,035
Total deferred tax liabilities	$5,091,275	$4,315,220
Deferred tax assets:		
NOL carryforward	$696,435	$425,620
Tax credit carryforward	254,157	226,057
Unbilled revenue - fuel costs	73,912	69,358
Environmental remediation	45,551	41,696
Rate refund	37,443	8,971
Deferred investment tax credits	37,425	39,916
Regulatory liabilities	37,012	51,600
Accrued liabilities and other	73,092	58,891
NOL and tax credit valuation allowances	(5,683)	(1,927)
Total deferred tax assets	$1,249,344	$920,182
Net deferred tax liability	$3,841,931	$3,395,038

7. Earnings Per Share

Basic EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents), such as equity forward agreements or stock options and other share-based compensation awards were settled.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents consisting of 401(k) equity awards and stock options, and in 2010, also had equity forward instruments. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated based on the treasury stock method.

Equity Forward Agreements
In August 2010, Xcel Energy Inc. entered into equity forward agreements in connection with a public offering of 21.85 million shares of its common stock. Under the equity forward agreements (Forward Agreements), Xcel Energy Inc. agreed to issue to the banking counterparty 21.85 million shares of its common stock.

The equity forward instruments were accounted for as equity and recorded at fair value at the execution of the Forward Agreements, and were not subsequently adjusted for changes in fair value until settlement. Based upon the market terms of the equity forward instruments, including initial pricing of $20.855 per share determined based on the August 2010 offering price of Xcel Energy Inc.'s common stock of $21.50 per share less underwriting fees of $0.645 per share, and as no premium on the transaction was owed either party to the Forward Agreements at execution, no fair value was recorded to equity for the instruments when the Forward Agreements were entered. The Forward Agreements settled on Nov. 29, 2010 and the proceeds of $449.8 million were recorded to common stock and additional paid in capital.

Share-Based Compensation

Common stock equivalents related to share-based compensation causing dilutive impact to EPS historically have included 401(k) equity awards and stock options. Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted, pending remaining service conditions.

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Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- RSU equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- PSP liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows for the years ending Dec. 31:

	2011			2010			2009		
(Amounts in thousands, except per share data)	Income	Share	Per Share Amount	Income	Share	Per Share Amount	Income	Share	Per Share Amount
Net income	$ 841,172			$ 755,834			$ 680,887		
Less: Dividend requirements on preferred stock	(3,534)			(4,241)			(4,241)		
Less: Premium on redemption of preferred stock	(3,260)			-			-		
Basic earnings per share:									
Earnings available to common shareholders	834,378	485,039	$ 1.72	751,593	462,052	$ 1.63	676,646	456,433	$ 1.48
Effect of dilutive securities:									
Equity forward instruments	-	-		-	700		-	-	
401(k) equity awards	-	576		-	639		-	705	
Stock options	-	-		-	-		-	1	
Diluted earnings per share:									
Earnings available to common shareholders	$ 834,378	485,615	$ 1.72	$ 751,593	463,391	$ 1.62	$ 676,646	457,139	$ 1.48

In 2011, 2010 and 2009, Xcel Energy Inc. had approximately 2.1 million, 5.4 million and 7.6 million weighted average options outstanding, respectively, that were antidilutive, and therefore, excluded from the earnings per share calculation.

8. Share-Based Compensation

Stock Options — Xcel Energy Inc. has incentive compensation plans under which stock options and other performance incentives are awarded to key employees. Xcel Energy Inc. has not granted stock options since December 2001.

Activity in stock options was as follows:

	2011		2010		2009	
(Awards in Thousands)	Awards	Average Exercise Price	Awards	Average Exercise Price	Awards	Average Exercise Price
Outstanding and exercisable at Jan. 1	2,498	$30.42	6,657	$28.17	8,460	$27.05
Exercised	(1,173)	25.90	(51)	19.31	(794)	19.84
Forfeited	-	-	-	-	(11)	20.04
Expired	(1,325)	34.42	(4,108)	26.91	(998)	25.40
Outstanding and exercisable at Dec. 31	-	-	2,498	30.42	6,657	28.17

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

(Thousands of Dollars)	2011	2010	2009
Market value of exercises	$30,761	$1,087	$16,429
Intrinsic value of options exercised (a)	380	93	670

(a)Intrinsic value is calculated as market price at exercise date less the option exercise price.

Cash received from stock options exercised and the actual tax benefit realized for the tax deductions from stock options exercised during the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2011	2010	2009
Cash received from stock options exercised	$30,381	$1,033	$15,759
Tax benefit realized for the tax deductions from stock options exercised	157	40	277

Restricted Stock — Certain employees may elect to receive shares of common or restricted stock under the Xcel Energy Inc. Executive Annual Incentive Award Plan. Restricted stock vests and settles in equal annual installments over a three-year period. Xcel Energy Inc. reinvests dividends on the restricted stock it holds while restrictions are in place. Restrictions also apply to the additional shares of restricted stock acquired through dividend reinvestment. If the restricted shares are forfeited, the employee is not entitled to the dividends on those shares. Restricted stock has a fair value equal to the market trading price of Xcel Energy Inc.'s stock at the grant date.

Xcel Energy Inc. granted shares of restricted stock for the years ended Dec. 31 as follows:

(Shares in Thousands)	2011	2010	2009
Granted shares	15	44	-
Grant date fair value	$23.62	$20.47	$-

A summary of the changes of nonvested restricted stock for the year ended Dec. 31, 2011 were as follows:

(Shares in Thousands)	Shares	Weighted Average Grant Date Fair Value
Nonvested restricted stock at Jan. 1	55	$ 20.28
Granted	15	23.62
Vested	(25)	20.53
Dividend equivalents	2	24.37
Nonvested restricted stock at Dec. 31	47	21.36

Restricted Stock Units (RSUs) — Xcel Energy Inc.'s Board of Directors has granted RSUs under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated in 2010). The plan allows the attachment of various performance goals to the RSUs granted. The performance goals may vary by plan year. At the end of the restricted performance period, the grants will be awarded if the performance goals are met. If the goals are not achieved by the end of the restricted performance period, all associated restricted stock units and dividend equivalents are forfeited.

For RSUs issued in 2009 and 2010, if the performance criteria have not been met within four years of the grant date, all RSUs, plus associated dividend equivalents, shall be forfeited. The performance conditions for RSUs granted in 2011 will be measured three years after the grant date, at which time the RSUs, plus associated dividend equivalents, will either be settled or forfeited. Payout of the RSUs and the lapsing of restrictions on the transfer of units are based on one of two separate performance criteria.

The performance conditions for a portion of the awarded units are based on EPS growth, with an additional condition that Xcel Energy Inc.'s annual dividend paid on its common stock remains at a specified amount per share or greater. RSUs issued in 2009 and 2010, plus associated dividend equivalents, will be settled and the restricted period will lapse after Xcel Energy Inc. achieves a specified level of EPS growth. RSUs issued in 2011, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years, with potential payouts ranging from 0 percent to 150 percent, depending on the level of EPS growth.

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The performance conditions for the remaining awarded units are based on environmental performance. RSUs issued in 2009 and 2010, plus associated dividend equivalents, will be settled and the restricted period will lapse after Xcel Energy Inc. achieves a specified level of environmental performance, based on established indicators. RSUs issued in 2011, plus associated dividend equivalents, will be settled or forfeited and the restricted period will lapse after three years with potential payouts ranging from 0 percent to 150 percent, depending on the level of environmental performance, based on established indicators.

The 2007 environmental RSUs met their target as of Dec. 31, 2009 and were settled in shares in February 2010. The 2007 RSUs measured on EPS growth and all 2008 RSUs met their targets as of Dec. 31, 2010 and were settled in shares in February 2011. The 2010 RSUs measured on EPS growth and all 2009 RSUs met their targets as of Dec. 31, 2011, and will be settled in shares in February 2012.

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

(Units in Thousands)	2011	2010	2009
Granted units	828	601	597
Weighted average grant date fair value	$23.63	$21.26	$18.88

A summary of the changes of nonvested RSUs for the year ended Dec. 31, 2011, were as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Nonvested restricted stock units at Jan. 1	1,138	$20.12
Granted	828	23.63
Forfeited	(270)	21.50
Vested	(1,091)	20.45
Dividend equivalents	68	21.18
Nonvested restricted stock units at Dec. 31	673	23.46

The total fair value of nonvested RSUs as of Dec. 31, 2011 was $18.6 million and the weighted average remaining contractual life was 2.0 years.

Approximately 1.1 million RSUs vested during 2011 at a total fair value of $30.1 million. Approximately 0.6 million RSUs vested during 2010 at a total fair value of $14.8 million. Approximately 0.04 million RSUs vested during 2009 at a total fair value of $0.8 million.

Stock Equivalent Unit Plan — Non-employee members of the Xcel Energy Inc. Board of Directors receive annual awards of stock equivalent units, with each unit having a value equal to one share of Xcel Energy Inc. common stock. The annual grants are vested as of the date of each member's election to the board of directors; there is no further service or other condition attached to the annual grants after the member has been elected to the board. Additionally, directors may elect to receive their fees in stock equivalent units in lieu of cash, and similarly have no further service or other conditions attached. Dividends on Xcel Energy Inc.'s common stock are converted to stock equivalent units and granted based on the number of stock equivalent units held by each participant as of the dividend date. The stock equivalent units are payable as a distribution of Xcel Energy Inc.'s common stock upon a director's termination of service.

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

(Units in Thousands)	2011	2010	2009
Granted units	60	66	72
Grant date fair value	$25.12	$21.14	$17.87

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A summary of the stock equivalent unit changes for the year ended Dec. 31, 2011 are as follows:

(Units in Thousands)	Units	Weighted Average Grant Date Fair Value
Stock equivalent units at Jan. 1	471	$ 19.90
Granted	60	25.12
Units distributed	(29)	20.31
Dividend equivalents	20	24.38
Stock equivalent units at Dec. 31	522	20.65

PSP Awards — Xcel Energy Inc.'s Board of Directors has granted PSP awards under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated effective in 2010). The plan allows Xcel Energy to attach various performance goals to the PSP awards granted. The PSP awards have been historically dependent on a single measure of performance, Xcel Energy Inc.'s TSR measured over a three-year period. Xcel Energy Inc.'s TSR is compared to the TSR of other companies in the EEI Investor-Owned Electrics index. At the end of the three-year period, potential payouts of the PSP awards range from 0 percent to 200 percent, depending on Xcel Energy Inc.'s TSR compared to the peer group.

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

(In Thousands)	2011	2010	2009
Awards granted	311	225	207

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

(In Thousands)	2011	2010	2009
Awards settled	305	267	293
Settlement amount (cash and common stock)	$ 7,200	$ 5,460	$ 5,195

The amount of cash used to settle Xcel Energy's PSP awards was $3.6 million and $2.7 million in 2011 and 2010, respectively.

Share-Based Compensation Expense — The vesting of the RSUs is predicated on the achievement of a performance condition, which is the achievement of an earnings per share or environmental measures target. RSU awards and restricted stock are considered to be equity awards, since the plan settlement determination (shares or cash) resides with Xcel Energy and not the participants. In addition, these awards have not been previously settled in cash and Xcel Energy plans to continue electing share settlement. The grant date fair value of RSUs and restricted stock is expensed as employees vest in their rights to those awards.

The PSP awards have been historically settled partially in cash, and therefore, do not qualify as an equity award, but rather are accounted for as a liability award. As liability awards, the fair value on which ratable expense is based, as employees vest in their rights to those awards, is remeasured each period based on the current stock price and performance conditions, and final expense is based on the market value of the shares on the date the award is settled.

The compensation costs related to share-based awards for the years ended Dec. 31 were as follows:

(Thousands of Dollars)	2011	2010	2009

Compensation cost for share-based awards (a) (b)	$45,006	$35,807	$29,672
Tax benefit recognized in income	17,559	13,964	11,471
Total compensation cost capitalized	3,857	3,646	3,636

(a) Compensation costs for share-based payment arrangements is included in other O&M expense in the consolidated statements of income.

(b) Included in compensation cost for share-based awards are matching contributions related to the Xcel Energy 401(k) plan, which totaled $21.6 million, $20.7 million and $19.3 million for the years ended 2011, 2010 and 2009, respectively.

The maximum aggregate number of shares of common stock available for issuance under the Xcel Energy Inc. 2005 Long-term Incentive Plan (as amended and restated effective Feb. 17, 2010) is 8.3 million shares. Under the Xcel Energy Inc. Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010), the total number of shares approved for issuance is 1.2 million shares.

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As of Dec. 31, 2011 and 2010, there was approximately $15.4 million and $18.6 million, respectively, of total unrecognized compensation cost related to nonvested share-based compensation awards. Xcel Energy expects to recognize that cost over a weighted average period of 1.9 years.

9. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its employees. Approximately 50 percent of employees that receive benefits are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2011:

- NSP-Minnesota had 2,033 and NSP-Wisconsin had 405 bargaining employees covered under a collective-bargaining agreement, which expires at the end of 2013. NSP-Minnesota also had an additional 228 nuclear operation bargaining employees covered under several collective-bargaining agreements, which expire at various dates in 2012 and 2013.
- PSCo had 2,122 bargaining employees covered under a collective-bargaining agreement, which expires in May 2014.
- SPS had 804 bargaining employees covered under a collective-bargaining agreement, which expires in October 2014.

The plans invest in various instruments which are disclosed under the accounting guidance for fair value measurements which establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring fair value. The three levels in the hierarchy and examples of each level are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reporting date. The types of assets included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as common stocks listed by the New York Stock Exchange.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts or priced with models using highly observable inputs, such as corporate bonds with pricing based on market interest rate curves and recent trades of similarly rated securities.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as private equity investments and real estate investments, for which the measurement of net asset value requires significant use of unobservable inputs when determining the fair value of the underlying fund investments, including equity in non-publicly traded entities and real estate properties.

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.

Xcel Energy bases the 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 8.73 percent, which is greater than the current assumption level. The pension cost determination assumes a forecasted mix of investment types over the long term. Investment returns were above the assumed levels of 7.50, 7.79 and 8.50 percent in 2011, 2010 and 2009, respectively. Xcel Energy continually reviews its pension assumptions. In 2012, Xcel Energy's expected investment return assumption is 7.10 percent.

The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity; however, as Xcel Energy has experienced in recent years, unusual market volatility can impact even well-diversified portfolios and significantly affect the return levels achieved by pension assets in any year.

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The following table presents the target pension asset allocations for Xcel Energy:

	2011	2010
Domestic and international equity securities	27 %	24 %
Long-duration fixed income securities	31	41
Short-to-intermediate fixed income securities	12	11
Alternative investments	27	17
Cash	3	7
Total	100 %	100 %

Xcel Energy’s ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan’s funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios, and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios. The aggregate projected asset allocation presented in the table above for the master pension trust results from the plan-specific strategies.

Pension Plan Assets

The following tables present, for each of the fair value hierarchy levels, Xcel Energy’s pension plan assets that are measured at fair value as of Dec. 31, 2011 and 2010:

	Dec. 31, 2011			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$147,590	$-	$-	$147,590
Derivatives	-	8,011	-	8,011
Government securities	-	301,999	-	301,999
Corporate bonds	-	606,001	-	606,001
Asset-backed securities	-	-	31,368	31,368
Mortgage-backed securities	-	-	73,522	73,522
Common stock	68,553	-	-	68,553
Private equity investments	-	-	159,363	159,363
Commingled funds	-	1,292,569	-	1,292,569
Real estate	-	-	37,106	37,106
Securities lending collateral obligation and other	-	(55,802)	-	(55,802)
Total	$216,143	$2,152,778	$301,359	$2,670,280

	Dec. 31, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$122,643	$135,710	$-	$258,353
Derivatives	-	8,140	-	8,140
Government securities	-	117,522	-	117,522
Corporate bonds	-	641,807	-	641,807
Asset-backed securities	-	-	26,986	26,986
Mortgage-backed securities	-	-	113,418	113,418
Common stock	117,899	-	-	117,899
Private equity investments	-	-	122,223	122,223
Commingled funds	-	1,152,386	-	1,152,386
Real estate	-	-	73,701	73,701

Securities lending collateral obligation and other	-	(91,727)	-	(91,727)
Total	$240,542	$1,963,838	$336,328	$2,540,708

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The following tables present the changes in Xcel Energy's Level 3 pension plan assets for the years ended Dec. 31, 2011, 2010 and 2009:

(Thousands of Dollars)	Jan. 1, 2011	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2011
Asset-backed securities	$ 26,986	$ 2,391	$ (2,504)	$ 4,495	$ 31,368
Mortgage-backed securities	113,418	1,103	(5,926)	(35,073)	73,522
Real estate	73,701	(629)	20,271	(56,237)	37,106
Private equity investments	122,223	3,971	12,412	20,757	159,363
Total	$ 336,328	$ 6,836	$ 24,253	$ (66,058)	$ 301,359

(Thousands of Dollars)	Jan. 1, 2010	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2010
Asset-backed securities	$ 47,825	$ 3,400	$ (7,078)	$ (17,161)	$ 26,986
Mortgage-backed securities	144,006	13,719	(19,095)	(25,212)	113,418
Real estate	66,704	(1,135)	8,235	(103)	73,701
Private equity investments	82,098	(1,008)	(24)	41,157	122,223
Total	$ 340,633	$ 14,976	$ (17,962)	$ (1,319)	$ 336,328

(Thousands of Dollars)	Jan. 1, 2009	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2009
Asset-backed securities	$ 77,398	$ 2,365	$ 45,920	$ (77,858)	$ 47,825
Mortgage-backed securities	166,610	5,531	97,939	(126,074)	144,006
Real estate	109,289	(569)	(42,638)	622	66,704
Private equity investments	81,034	-	(5,682)	6,746	82,098
Total	$ 434,331	$ 7,327	$ 95,539	$ (196,564)	$ 340,633

Benefit Obligations — A comparison of the actuarially computed pension benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2011	2010
Accumulated Benefit Obligation at Dec. 31	$ 3,073,637	$ 2,865,845
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 3,030,292	$ 2,829,631
Service cost	77,319	73,147
Interest cost	161,412	165,010
Plan amendments	-	18,739
Actuarial loss	195,369	169,203
Benefit payments	(238,173)	(225,438)

Obligation at Dec. 31	$3,226,219	$3,030,292

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(Thousands of Dollars)	2011	2010
Change in Fair Value of Plan Assets:		
Fair value of plan assets at Jan. 1	$2,540,708	$2,449,326
Actual return on plan assets	230,401	282,688
Employer contributions	137,344	34,132
Benefit payments	(238,173)	(225,438)
Fair value of plan assets at Dec. 31	$2,670,280	$2,540,708
Funded Status of Plans at Dec. 31:		
Funded status (a)	$(555,939)	$(489,584)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 1,610,946	$ 1,502,888
Prior service cost	18,432	40,965
Total	$ 1,629,378	$ 1,543,853
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	$ 123,814	$ 92,765
Noncurrent regulatory assets	1,435,372	1,386,125
Deferred income taxes	28,759	26,592
Net-of-tax accumulated other comprehensive income	41,433	38,371
Total	$ 1,629,378	$ 1,543,853
Measurement date	Dec. 31, 2011	Dec. 31, 2010
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	5.00 %	5.50 %
Expected average long-term increase in compensation level	4.00	4.00
Mortality table	RP 2000	RP 2000

(a)Amounts are recognized in noncurrent liabilities on Xcel Energy's consolidated balance sheet.

Cash Flows — Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding for 2008 through 2010 for Xcel Energy's pension plans. Required contributions were made in 2011 and 2012 to meet minimum funding requirements.

The Pension Protection Act changed the minimum funding requirements for defined benefit pension plans beginning in 2008. The following are the pension funding contributions, both voluntary and required, made by Xcel Energy for 2010 through 2012:

- In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans;
- In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans;
- In 2010, contributions of $34 million were made to the Xcel Energy Pension Plan.
- For future years, we anticipate contributions will be made as necessary.

Plan Amendments — No amendments occurred during 2011 to the Xcel Energy pension plans.

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Benefit Costs — The components of Xcel Energy's net periodic pension cost were:

(Thousands of Dollars)	2011	2010	2009
Service cost	$77,319	$73,147	$65,461
Interest cost	161,412	165,010	169,790
Expected return on plan assets	(221,600)	(232,318)	(256,538)
Amortization of prior service cost	22,533	20,657	24,618
Amortization of net loss	78,510	48,315	12,455
Net periodic pension cost	118,174	74,811	15,786
Costs not recognized due to effects of regulation	(37,198)	(27,027)	(2,891)
Net benefit cost recognized for financial reporting	$80,976	$47,784	$12,895
Significant Assumptions Used to Measure Costs:			
Discount rate	5.50 %	6.00 %	6.75 %
Expected average long-term increase in compensation level	4.00	4.00	4.00
Expected average long-term rate of return on assets	7.50	7.79	8.50

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 2012 pension cost calculations will be 7.10 percent.

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 consolidated 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 $27.1 million in 2011, $27.3 million in 2010 and $21.9 million in 2009.

Postretirement Health Care Benefits

Xcel Energy has a contributory health and welfare benefit plan that provides health care and death benefits to certain Xcel Energy retirees.

- The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999.
- Xcel Energy discontinued contributing toward health care benefits for former NCE nonbargaining employees retiring after June 30, 2003.
    - Employees of NCE who retired in 2002 continue to receive employer-subsidized health care benefits.
- Nonbargaining employees of the former NCE who retired after 1998, bargaining employees of the former NCE who retired after 1999 and nonbargaining employees of NCE who retired after June 30, 2003, are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In 1993, Xcel Energy adopted accounting guidance regarding other non-pension postretirement benefits and elected to amortize the unrecognized 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 postretirement benefit costs. The Colorado jurisdictional postretirement benefit 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. PSCo transitioned to full accrual accounting for postretirement benefit costs between 1993 and 1997.

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Plan Assets — Certain state agencies that regulate Xcel Energy Inc.'s utility subsidiaries also have issued guidelines related to the funding of postretirement benefit costs. SPS is required to fund postretirement benefit costs for Texas and New Mexico jurisdictional amounts collected in rates and PSCo is required to fund postretirement benefit costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Also, a portion of the assets contributed on behalf of nonbargaining retirees has been funded into a sub-account of the Xcel Energy pension plans. These assets are invested in a manner consistent with the investment strategy for the pension plan.

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 asset portfolio. The assets are invested in a portfolio according to Xcel Energy's return, liquidity and diversification objectives to provide a source of funding for plan obligations and minimize the necessity of contributions to the plan, within appropriate levels of risk. The principal mechanism for achieving these objectives is the projected allocation of assets to selected asset classes, given the long-term risk, return, correlation, and liquidity characteristics of each particular asset class. There were no significant concentrations of risk in any particular industry, index, or entity. Investment-return volatility is not considered to be a material factor in postretirement health care costs.

The following tables present, for each of the fair value hierarchy levels, Xcel Energy's postretirement benefit plan assets that are measured at fair value as of Dec. 31, 2011 and 2010:

	Dec. 31, 2011			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$58,037	$-	$-	$58,037
Derivatives	-	13,178	-	13,178
Government securities	-	65,746	-	65,746
Corporate bonds	-	61,524	-	61,524
Asset-backed securities	-	-	7,867	7,867
Mortgage-backed securities	-	-	27,253	27,253
Preferred stock	-	423	-	423
Common stock	351	-	-	351
Private equity investments	-	-	479	479
Commingled funds	-	202,912	-	202,912
Real estate	-	-	144	144
Securities lending collateral obligation and other	-	(11,079)	-	(11,079)
Total	$58,388	$332,704	$35,743	$426,835

	Dec. 31, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Cash equivalents	$72,573	$76,352	$-	$148,925
Derivatives	-	13,632	-	13,632
Government securities	-	3,402	-	3,402
Corporate bonds	-	70,752	-	70,752
Asset-backed securities	-	-	2,585	2,585
Mortgage-backed securities	-	-	19,212	19,212
Preferred stock	-	507	-	507
Commingled funds	-	102,962	-	102,962
Securities lending collateral obligation and other	-	70,253	-	70,253
Total	$72,573	$337,860	$21,797	$432,230

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The following tables present the changes in Xcel Energy's Level 3 postretirement benefit plan assets for the years ended Dec. 31, 2011, 2010 and 2009:

(Thousands of Dollars)	Jan. 1, 2011	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2011
Asset-backed securities	$ 2,585	$ (10)	$ (664)	$ 5,956	$ 7,867
Mortgage-backed securities	19,212	(1,669)	2,623	7,087	27,253
Real estate	-	(2)	(34)	180	144
Private equity investments	-	12	53	414	479
Total	$ 21,797	$ (1,669)	$ 1,978	$ 13,637	$ 35,743

(Thousands of Dollars)	Jan. 1, 2010	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2010
Asset-backed securities	$ 8,293	$ (259)	$ 2,073	$ (7,522)	$ 2,585
Mortgage-backed securities	47,078	(927)	15,642	(42,581)	19,212
Total	$ 55,371	$ (1,186)	$ 17,715	$ (50,103)	$ 21,797

(Thousands of Dollars)	Jan. 1, 2009	Net Realized Gains (Losses)	Net Unrealized Gains (Losses)	Purchases, Issuances, and Settlements, Net	Dec. 31, 2009
Asset-backed securities	$ 8,705	$ 4	$ 1,025	$ (1,441)	$ 8,293
Mortgage-backed securities	69,988	733	2,289	(25,932)	47,078
Total	$ 78,693	$ 737	$ 3,314	$ (27,373)	$ 55,371

Benefit Obligations — A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy is presented in the following table:

(Thousands of Dollars)	2011	2010
Change in Projected Benefit Obligation:		
Obligation at Jan. 1	$ 794,905	$ 728,902
Service cost	4,824	4,006
Interest cost	42,086	42,780
Medicare subsidy reimbursements	3,518	5,423
ERRP proceeds shared with retirees	4,269	-
Plan amendments	(26,630)	-
Plan participants' contributions	15,690	14,315
Actuarial loss	8,823	68,126
Benefit payments	(70,638)	(68,647)
Obligation at Dec. 31	$ 776,847	$ 794,905
Change in Fair Value of Plan Assets:		

Fair value of plan assets at Jan. 1	$432,230	$384,689
Actual return on plan assets	535	53,430
Plan participants' contributions	15,690	14,315
Employer contributions	49,018	48,443
Benefit payments	(70,638)	(68,647)
Fair value of plan assets at Dec. 31	$426,835	$432,230

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(Thousands of Dollars)	2011	2010
Funded Status of Plans at Dec. 31:		
Funded status	$ (350,012)	$ (362,675)
Current assets	332	-
Current liabilities	(7,594)	(5,392)
Noncurrent liabilities	(342,750)	(357,283)
Net postretirement amounts recognized on consolidated balance sheets	$ (350,012)	$ (362,675)
Amounts Not Yet Recognized as Components of Net Periodic Benefit Cost:		
Net loss	$ 246,846	$ 221,335
Prior service credit	(50,652)	(28,954)
Transition obligation	15,147	29,591
Total	$ 211,341	$ 221,972
Amounts Related to the Funded Status of the Plans Have Been Recorded as Follows Based Upon Expected Recovery in Rates:		
Current regulatory assets	$ 26,139	$ 20,225
Noncurrent regulatory assets	176,730	197,952
Current regulatory liabilities	(1,866)	-
Noncurrent regulatory liabilities	-	(6,423)
Deferred income taxes	4,207	4,159
Net-of-tax accumulated other comprehensive income	6,131	6,059
Total	$ 211,341	$ 221,972
Measurement date	Dec. 31, 2011	Dec. 31, 2010
Significant Assumptions Used to Measure Benefit Obligations:		
Discount rate for year-end valuation	5.00 %	5.50 %
Mortality table	RP 2000	RP 2000
Health care costs trend rate - initial	6.31 %	6.50 %

Effective Dec. 31, 2011, the ultimate trend assumption remained unchanged at 5.0 percent. The period until the ultimate rate is reached remained unchanged at eight years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost increases experienced by Xcel Energy's retiree medical plan.

A 1-percent change in the assumed health care cost trend rate would have the following effects on Xcel Energy:

	One Percentage Point	
(Thousands of Dollars)	Increase	Decrease
APBO	$79,710	$(65,195)
Service and interest components	5,598	(4,456)

Cash Flows — The postretirement health care plans have no funding requirements under income tax and other retirement-related regulations other than fulfilling benefit payment obligations, when claims are presented and approved under the plans. Additional cash funding requirements are prescribed by certain state and federal rate regulatory authorities, as discussed previously. Xcel Energy contributed $49.0 million during 2011 and $48.4 million during 2010 and expects to contribute approximately $39.1 million during 2012.

Plan Amendments — The 2011 decrease of the projected Xcel Energy postretirement health and welfare benefit obligation for plan amendments is due to changes in the participant co-pay structure for certain retiree groups and the elimination of dental and vision benefits for some non-bargaining retirees.

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Benefit Costs — The components of Xcel Energy's net periodic postretirement benefit costs were:

(Thousands of Dollars)	2011	2010	2009
Service cost	$4,824	$4,006	$4,665
Interest cost	42,086	42,780	50,412
Expected return on plan assets	(31,962)	(28,529)	(22,775)
Amortization of transition obligation	14,444	14,444	14,444
Amortization of prior service cost	(4,932)	(4,932)	(2,726)
Amortization of net loss	13,294	11,643	19,329
Net periodic postretirement benefit cost	37,754	39,412	63,349
Additional cost recognized due to effects of regulation	3,891	3,891	3,891
Net benefit cost recognized for financial reporting	$41,645	$43,303	$67,240
Significant Assumptions Used to Measure Costs:			
Discount rate	5.50 %	6.00 %	6.75 %
Expected average long-term rate of return on assets (before tax)	7.50	7.50	7.50

Projected Benefit Payments

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

(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
2012	$ 270,101	$ 57,461	$ 4,523	$ 52,938
2013	253,333	57,318	4,871	52,447
2014	261,854	58,396	5,175	53,221
2015	263,129	59,880	5,471	54,409
2016	264,885	61,375	5,751	55,624
2017-2021	1,328,001	315,139	32,659	282,480

Multiemployer Plans

NSP-Minnesota and NSP-Wisconsin each contribute to several union multiemployer pension and other postretirement benefit plans, none of which are individually significant. These plans provide pension and postretirement health care benefits to certain union employees, including electrical workers, boilermakers, and other construction and facilities workers who may perform services for more than one employer during a given period and do not participate in the NSP-Minnesota and NSP-Wisconsin sponsored pension and postretirement health care plans. Contributing to these types of plans creates risk that differs from providing benefits under NSP-Minnesota and NSP-Wisconsin sponsored plans, in that if another participating employer ceases to contribute to a multiemployer plan, additional unfunded obligations may need to be funded over time by remaining participating employers.

Contributions to multiemployer plans were as follows for the years ended Dec. 31, 2011, 2010 and 2009. There were no significant changes to the nature or magnitude of the participation of NSP-Minnesota and NSP-Wisconsin in multiemployer plans for the years presented:

(Thousands of Dollars)	2011	2010	2009
Multiemployer pension contributions:			
NSP-Minnesota	$17,811	$13,461	$11,348
NSP-Wisconsin	169	170	116
Total	$17,980	$13,631	$11,464
Multiemployer other postretirement benefit contributions:			
NSP-Minnesota	$336	$153	$140
Total	$336	$153	$140

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10. Other Income, Net

Other income (expense), net for the years ended Dec. 31 consisted of the following:

(Thousands of Dollars)	2011	2010	2009
Interest income	$10,639	$11,023	$14,928
COLI settlement (See Note 6)	-	25,000	-
Other nonoperating income	3,722	1,689	3,650
Life insurance policy expense	(4,785)	(6,529)	(8,646)
Other nonoperating expense	(321)	(40)	(161)
Other income, net	$9,255	$31,143	$9,771

11. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with discounted cash flow or option pricing models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Given the limited observability of inputs to the valuation of the underlying fund investments of the private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Debt securities are primarily priced using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, which also require significant, subjective risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated principal prepayments. Therefore, fair value measurements for asset-backed and mortgage-backed securities have been assigned a Level 3.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes utilizing current market interest rate forecasts.

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Commodity derivatives — The methods utilized to measure the fair value of commodity derivatives include the use of forward prices and volatilities to value commodity forwards and options. Levels are assigned to these fair value measurements based on the significance of the use of subjective forward price and volatility forecasts for commodities and delivery locations with limited observability, or the significance of contractual settlements that extend to periods beyond those readily observable on active exchanges or quoted by brokers. Electric commodity derivatives include FTRs, for which fair value is determined using complex predictive models and inputs including forward commodity prices as well as subjective forecasts of retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management’s forecasts for several of these inputs, fair value measurements for FTRs have been assigned a Level 3.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty’s ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities presented in the consolidated balance sheets.

Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota’s regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the decommissioning fund were $79.8 million and $82.5 million at Dec. 31, 2011 and Dec. 31, 2010, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $87.5 million and $65.2 million at Dec. 31, 2011 and Dec. 31, 2010, respectively.

The following tables present the cost and fair value of Xcel Energy’s non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Dec. 31, 2011 and 2010:

		Dec. 31, 2011 Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$26,123	$7,103	$19,020	$-	$26,123
Commingled funds	320,798	-	311,105	-	311,105
International equity funds	63,781	-	58,508	-	58,508
Private equity investments	9,203	-	-	9,203	9,203
Real estate	24,768	-	-	26,395	26,395
Debt securities:					

Government securities	116,490	-	117,256	-	117,256
U.S. corporate bonds	187,083	-	193,516	-	193,516
International corporate bonds	35,198	-	35,804	-	35,804
Municipal bonds	60,469	-	64,731	-	64,731
Asset-backed securities	16,516	-	-	16,501	16,501
Mortgage-backed securities	75,627	-	-	78,664	78,664
Equity securities:					
Common stock	408,122	398,625	-	-	398,625
Total	$1,344,178	$405,728	$799,940	$130,763	$1,336,431

[a] Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $92.7 million of equity investments in unconsolidated subsidiaries and $34.3 million of miscellaneous investments.

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		Dec. 31, 2010 Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$83,837	$76,281	$7,556	$-	$83,837
Commingled funds	131,000	-	133,080	-	133,080
International equity funds	54,561	-	58,584	-	58,584
Debt securities:					
Government securities	146,473	-	146,654	-	146,654
U.S. corporate bonds	279,028	-	288,304	-	288,304
International corporate bonds	1,233	-	1,581	-	1,581
Municipal bonds	100,277	-	97,557	-	97,557
Asset-backed securities	32,558	-	-	33,174	33,174
Mortgage-backed securities	68,072	-	-	72,589	72,589
Equity securities:					
Common stock	436,334	435,270	-	-	435,270
Total	$1,333,373	$511,551	$733,316	$105,763	$1,350,630

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $97.6 million of equity investments in unconsolidated subsidiaries and $28.2 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	Dec. 31, 2011
Asset-backed securities	$ 33,174	$16,518	$(32,560)	$ (631)	$ 16,501
Mortgage-backed securities	72,589	168,688	(161,134)	(1,479)	78,664
Real estate	-	24,768	-	1,627	26,395
Private equity investments	-	9,203	-	-	9,203
Total	$ 105,763	$219,177	(193,694)	$ (483)	$ 130,763

(Thousands of Dollars)	Jan. 1, 2010	Purchases	Settlements	Gains Recognized as Regulatory Assets and Liabilities	Dec. 31, 2010
Asset-backed securities	$ 11,918	$ 38,871	$ (17,878)	$ 263	$ 33,174
Mortgage-backed securities	81,189	63,497	(75,701)	3,604	72,589
Total	$ 93,107	$ 102,368	(93,579)	$ 3,867	$ 105,763

(Thousands of Dollars)	Jan. 1, 2009	Purchases	Settlements	Gains Recognized as	Dec. 31, 2009

				Regulatory Assets and Liabilities	
Asset-backed securities	$10,962	$7,271	$(7,755)	$1,440	$11,918
Mortgage-backed securities	98,461	17,943	(45,815)	10,600	81,189
Total	$109,423	$25,214	(53,570)	$12,040	$93,107

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The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Dec. 31, 2011:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$113,179	$-	$4,077	$-	$117,256
U.S. corporate bonds	304	35,437	139,880	17,895	193,516
International corporate bonds	-	8,454	23,501	3,849	35,804
Municipal bonds	-	-	40,585	24,146	64,731
Asset-backed securities	-	9,907	6,594	-	16,501
Mortgage-backed securities	-	1,731	1,041	75,892	78,664
Debt securities	$113,483	$55,529	$215,678	$121,782	$506,472

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather.

Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Dec. 31, 2011, accumulated OCI related to interest rate derivatives included $0.9 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

At Dec. 31, 2011, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million. These interest rate swaps were designated as hedges, and as such, changes in fair value are recorded to OCI. In addition, Xcel Energy entered into interest rate swaps with a notional amount of $175 million during the year which were settled in conjunction with the Xcel Energy Inc. debt issuance in September 2011. See Note 4 to for further discussions of long-term borrowings.

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

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At Dec. 31, 2011, Xcel Energy had various vehicle fuel related contracts designated as cash flow hedges extending through December 2014. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the years ended Dec. 31, 2011 and 2010.

At Dec. 31, 2011, accumulated OCI related to commodity derivative cash flow hedges included $0.2 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

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The following table details the gross notional amounts of commodity forwards, options and FTRs at Dec. 31, 2011 and Dec. 31, 2010:

(Amounts in Thousands) (a)(b)	Dec. 31, 2011	Dec. 31, 2010
MWh of electricity	38,822	46,794
MMBtu of natural gas	40,736	75,806
Gallons of vehicle fuel	600	800

(a)Amounts are not reflective of net positions in the underlying commodities.
(b)Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated OCI, included in the consolidated statements of common stockholders' equity and comprehensive income, is detailed in the following table:

(Thousands of Dollars)	2011	2010	2009
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(8,094)	$(6,435)	$(13,113)
After-tax net unrealized losses related to derivatives accounted for as hedges	(38,292)	(4,289)	(710)
After-tax net realized losses on derivative transactions reclassified into earnings	648	2,630	7,388
Accumulated other comprehensive loss related to cash flow hedges at Dec. 31	$(45,738)	$(8,094)	$(6,435)

Xcel Energy had no derivative instruments designated as fair value hedges during the years ended Dec. 31, 2011 and Dec. 31, 2010.

The following tables detail the impact of derivative activity during the years ended Dec. 31, 2011 and Dec. 31, 2010, on OCI, regulatory assets and liabilities, and income:

	Dec. 31, 2011				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (63,573)	$ -	$ 1,424 (a)	$ -	$ -
Vehicle fuel and other commodity	195	-	(178) (e)	-	-
Total	$ (63,378)	$ -	$ 1,246	$ -	$ -
Other derivative instruments					

Trading commodity	$	-	$	-		$	-	$	-			$	6,418	(b)
Electric commodity		-		49,818			-		(40,492	)	(c)		-	
Natural gas commodity		-		(111,574	)		-		91,743		(d)		(382	)(b)
Total	$	-	$	(61,756	)	$	-	$	51,251			$	6,036	

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	Dec. 31, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (7,210)	$ -	$ 1,107 (a)	$ -	$ -
Vehicle fuel and other commodity	(238)	-	3,474 (e)	-	-
Total	$ (7,448)	$ -	$ 4,581	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 11,004 (b)
Electric commodity	-	3,969	-	(21,840) (c)	-
Natural gas commodity	-	(105,396)	-	51,034 (d)	-
Other	-	-	-	-	135 (b)
Total	$ -	$ (101,427)	$ -	$ 29,194	$ 11,139

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these total gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Recorded to O&M expenses.

Credit Related Contingent Features — Contract provisions of the derivative instruments that the utility subsidiaries enter into may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s subsidiaries were downgraded below investment grade, contracts underlying $8.3 million and $5.6 million of derivative instruments in a gross liability position at Dec. 31, 2011 and Dec. 31, 2010, respectively, would have required Xcel Energy Inc.'s subsidiaries to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $9.3 million and $9.8 million, respectively. At Dec. 31, 2011 and Dec. 31, 2010, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Dec. 31, 2011 and Dec. 31, 2010.

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Recurring Fair Value Measurements — The following table presents for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at Dec. 31, 2011:

	Dec. 31, 2011					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$169	$-	$169	$ (76)	$93
Other derivative instruments:						
Trading commodity	-	32,682	-	32,682	(13,391)	19,291
Electric commodity	-	-	13,333	13,333	(1,471)	11,862
Total current derivative assets	$-	$32,851	$13,333	$46,184	$ (14,938)	31,246
Purchased power agreements (a)						33,094
Current derivative instruments						$64,340
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$107	$-	$107	$ (59)	$48
Other derivative instruments:						
Trading commodity	-	36,599	-	36,599	(5,540)	31,059
Total noncurrent derivative assets	$-	$36,706	$-	$36,706	$ (5,599)	31,107
Purchased power agreements (a)						121,780
Noncurrent derivative instruments						$152,887

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(Thousands of Dollars)	Dec. 31, 2011 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$-	$57,749	$-	$57,749	$ -	$57,749
Other derivative instruments:						
Trading commodity	-	27,891	-	27,891	(14,417)	13,474
Electric commodity	-	698	916	1,614	(1,471)	143
Natural gas commodity	418	70,119	-	70,537	(7,486)	63,051
Total current derivative liabilities	$418	$156,457	$916	$157,791	$ (23,374)	134,417
Purchased power agreements (a)						22,997
Current derivative instruments						$157,414
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$20,966	$-	$20,966	$ (5,599)	$15,367
Total noncurrent derivative liabilities	$-	$20,966	$-	$20,966	$ (5,599)	15,367
Purchased power agreements (a)						248,539
Noncurrent derivative instruments						$263,906

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

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The following table presents for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at Dec. 31, 2010:

	Dec. 31, 2010					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$126	$-	$126	$ -	$126
Other derivative instruments:						
Trading commodity	487	37,019	-	37,506	(21,352)	16,154
Electric commodity	-	-	3,619	3,619	(1,226)	2,393
Natural gas commodity	-	1,595	-	1,595	(1,219)	376
Total current derivative assets	$487	$38,740	$3,619	$42,846	$ (23,797)	19,049
Purchased power agreements (a)						35,030
Current derivative instruments						$54,079
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$150	$-	$150	$ -	$150
Other derivative instruments:						
Trading commodity	-	32,621	-	32,621	(4,595)	28,026
Natural gas commodity	-	1,246	-	1,246	(269)	977
Total noncurrent derivative assets	$-	$34,017	$-	$34,017	$ (4,864)	29,153
Purchased power agreements (a)						154,873
Noncurrent derivative instruments						$184,026

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	Dec. 31, 2010					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Other derivative instruments:						
Trading commodity	$392	$30,608	$-	$31,000	$ (24,007)	$6,993
Electric commodity	-	-	1,227	1,227	(1,227)	-
Natural gas commodity	20	52,709	-	52,729	(21,169)	31,560
Total current derivative liabilities	$412	$83,317	$1,227	$84,956	$ (46,403)	38,553
Purchased power agreements (a)						23,192
Current derivative instruments						$61,745
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$18,878	$-	$18,878	$ (4,596)	$14,282
Natural gas commodity	-	438	-	438	(269)	169
Total noncurrent derivative liabilities	$-	$19,316	$-	$19,316	$ (4,865)	14,451
Purchased power agreements (a)						271,535
Noncurrent derivative instruments						$285,986

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table presents the changes in Level 3 commodity derivatives for the years ended Dec. 31, 2011, 2010 and 2009:

	Year Ended Dec. 31		
(Thousands of Dollars)	2011	2010	2009
Balance at Jan. 1	$2,392	$28,042	$23,221
Purchases	33,609	10,813	9,077
Settlements	(36,555)	(25,261)	(18,316)
Transfers (out of) into Level 3	-	(13,525)	1,280
Net transactions recorded during the period:			

Gains recognized in earnings (a)	69	6,237	8,228
Gains (losses) recognized as regulatory assets and liabilities	12,902	(3,914)	4,552
Balance at Dec. 31	$12,417	$2,392	$28,042

[a] These unrealized amounts relate to commodity derivatives held at the end of the period.

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Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for the year ended Dec. 31, 2011. The following table presents the transfers that occurred from Level 3 to Level 2 during the year ended Dec. 31, 2010.

(Thousands of Dollars)	Year Ended Dec. 31, 2010
Trading commodity derivatives not designated as cash flow hedges:	
Current assets	$ 7,271
Noncurrent assets	26,438
Current liabilities	(4,115)
Noncurrent liabilities	(16,069)
Total	$ 13,525

There were no transfers of amounts from Level 2 to Level 3, or any transfers to or from Level 1 for the year ended Dec. 31, 2010. The transfer of amounts from Level 3 to Level 2 in the year ended Dec. 31, 2010 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

Fair Value of Long-Term Debt

As of Dec. 31, 2011 and 2010, other financial instruments for which the carrying amount did not equal fair value were as follows:

	2011		2010	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$9,908,435	$11,734,798	$9,318,559	$10,224,845

The fair value 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, 2011 and 2010. 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.

12. Rate Matters

NSP-Minnesota

Pending Regulatory Proceedings — MPUC

Base Rate

NSP-Minnesota - Minnesota Electric Rate Case — In November 2010, NSP-Minnesota filed a request with the MPUC to increase electric rates in Minnesota for 2011 by approximately $150 million, or an increase of 5.62 percent and an additional increase of $48.3 million, or 1.81 percent in 2012. The rate filing was based on a 2011 forecast test year and included a requested ROE of 11.25 percent, an electric rate base of approximately $5.6 billion and an equity ratio of 52.56 percent. The MPUC approved an interim rate increase of $123 million, subject to refund, effective Jan. 2, 2011.

In June 2011, NSP-Minnesota revised its requested rate increase to $122.8 million, reflecting a revised ROE of 10.85 percent and other adjustments. The DOER revised its recommended rate increase to approximately $84.7 million in 2011 and an additional rate increase of $34 million in 2012, reflecting an ROE of 10.37 percent. The primary differences between the NSP-Minnesota requested rate increase and the DOER updated recommendation were associated with ROE and compensation related issues.

In August 2011, NSP-Minnesota submitted supplemental testimony, revising its requested rate increase to approximately $122 million for 2011 and a 2012 step increase of approximately $29 million. The revisions were due to delays in the Monticello nuclear plant extended power uprate.

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In November 2011, NSP-Minnesota reached a settlement agreement with the Xcel Large Industrials, the Minnesota Chamber of Commerce, the Commercial Group and Verso Paper Corp., which settled all financial issues and several rate design issues between the signing parties. The settlement includes a rate increase of approximately $58.0 million in 2011 and an incremental rate increase of $14.8 million in 2012 based on an ROE of 10.37 percent. The settlement agreement reflects a reduction to depreciation expense and NSP-Minnesota's rate request by $30 million with an additional adjustment of $7.5 million related to employee compensation. The settlement also provides NSP-Minnesota the ability to seek deferred accounting for incremental property tax increases associated with electric and natural gas businesses in 2012, which is currently projected to increase by approximately $28 million. NSP-Minnesota also agreed to not file an electric rate case prior to Nov. 1, 2012, provided that both the settlement and the property tax filing are approved by the MPUC. NSP-Minnesota has recorded a provision for revenue subject to refund of approximately $67.4 million for 2011 and has reduced depreciation expense by $30 million.

In February 2012, the ALJ recommended MPUC approval of the settlement agreement. In addition, NSP-Minnesota filed to reduce the interim rate request to $72.8 million to align with the settlement agreement. A decision is expected by the MPUC in the first half of 2012.

Pending Regulatory Proceedings — NDPSC

NSP-Minnesota – North Dakota Electric Rate Case — In December 2010, NSP-Minnesota filed a request with the NDPSC to increase 2011 electric rates in North Dakota by approximately $19.8 million, or an increase of 12 percent in 2011 and a step increase of $4.2 million, or 2.6 percent in 2012. The rate filing is based on a 2011 forecast test year and includes a requested ROE of 11.25 percent, an electric rate base of approximately $328 million and an equity ratio of 52.56 percent.

The NDPSC approved an interim rate increase of approximately $17.4 million, subject to refund, effective Feb. 18, 2011. NSP-Minnesota has recorded a provision for revenue subject to refund of approximately $2.4 million for 2011. The interim rates will remain in effect until the NDPSC makes its final decision on the case.

In May 2011, NSP-Minnesota revised its rate request to approximately $18.0 million, or an increase of 11 percent, for 2011 and $2.4 million, or 1.4 percent, for the additional step increase in 2012, due to the termination of the Merricourt wind project.

In September 2011, NSP-Minnesota reached a settlement with the NDPSC Advocacy Staff. If approved by the NDPSC, the settlement would result in a rate increase of $13.7 million in 2011 and an additional step increase of $2.0 million in 2012, based on a 10.4 percent ROE and black box settlement for all other issues. To address 2011 sales coming in below test year projections, the settlement includes a true-up to 2012 non-fuel revenues plus the settlement rate increase.

An NDPSC decision is expected in March 2012.

Pending Regulatory Proceedings — SDPUC

NSP-Minnesota – South Dakota Electric Rate Case — In June 2011, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $14.6 million annually, effective in 2012. The proposed increase included $0.7 million in revenues currently recovered through automatic recovery mechanisms. The request is based on a 2010 historic test year adjusted for known and measurable changes, a requested ROE of 11 percent, a rate base of $323.4 million and an equity ratio of 52.48 percent. NSP-Minnesota also requested approval of a nuclear cost recovery rider to recover the actual investment cost of the Monticello nuclear plant life cycle management and extended power uprate project that is not reflected in the test year.

As a result of delays in the rate case process, interim rates of $12.7 million were implemented Jan. 2, 2012. A final decision is expected in the first half of 2012.

Electric, Purchased Gas and Resource Adjustment Incentive Clauses

NSP-Minnesota has several retail adjustment clauses that recover fuel, purchased energy, other resource costs, lost margins and/or performance incentives, which are generally recovered concurrently through riders and base rates. At Dec. 31, 2011, pending adjustment clauses, which contain amounts related to incentive programs were as follows:

CIP Rider — CIP expenses are recovered through base rates and a rider that is adjusted annually. Under the 2010 electric CIP rider request approved by the MPUC in October 2010, NSP-Minnesota recovered $84.4 million through the rider during November 2010 to December 2011. This is in addition to $60.9 million recovered through base rates. During December 2010 to December 2011, NSP-Minnesota recovered $27.4 million through the natural gas CIP rider approved in November 2010. This is in addition to $4.4 million recovered in base rates.

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In January 2012, the MPUC approved NSP-Minnesota’s annual electric rider petition requesting recovery of $74.7 million of electric CIP expenses and financial incentives to be recovered during February 2012 through December 2012. In December 2011, the MPUC approved NSP-Minnesota’s annual gas rider petition requesting $10.6 million of natural gas CIP expenses and financial incentives to be recovered during January 2012 through December 2012. This proposed recovery through the riders is in addition to an estimated $48.3 million and $3.8 million through electric and gas base rates, respectively.

NSP-Wisconsin

Recently Concluded Regulatory Proceedings — PSCW

Base Rate

NSP-Wisconsin 2011 Electric and Gas Rate Case — In June 2011, NSP-Wisconsin filed a request with the PSCW to increase electric rates approximately $29.2 million, or 5.1 percent and natural gas rates approximately $8.0 million, or 6.6 percent effective Jan. 1, 2012. The rate filing is based on a 2012 forecast test year and includes a requested ROE of 10.75 percent, an equity ratio of 52.54 percent, an electric rate base of approximately $718 million and a natural gas rate base of $84 million.

In December 2011, the PSCW approved an electric rate increase of approximately $12.2 million or 2.1 percent, and a natural gas rate increase of $2.9 million or 2.4 percent, with new rates effective Jan. 1, 2012. The primary reason for the natural gas rate reduction from the original request was the PSCW decision to deny NSP-Wisconsin’s proposal to pre-collect certain manufactured gas plant remediation costs. The primary reasons for the electric rate reduction were updated 2012 electric fuel costs and the delays in the Monticello nuclear plant extended life cycle management and power uprate project. The rate increases were based on a 10.4 percent ROE and an equity ratio of 52.59 percent.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

Base Rate

PSCo 2010 Gas Rate Case — In December 2010, PSCo filed a request with the CPUC to increase Colorado retail gas rates by $27.5 million on an annual basis. In March 2011, PSCo revised its requested rate increase to $25.6 million. The revised request was based on a 2011 forecast test year, a 10.9 percent ROE, a rate base of $1.1 billion and an equity ratio of 57.1 percent. PSCo proposed recovering $23.2 million of test year capital and O&M expenses associated with several pipeline integrity costs plus an amortization of similar costs that have been accumulated and deferred since the last rate case in 2006. PSCo also proposed removing the earnings on gas in underground storage from base rates.

In August 2011, the CPUC approved a comprehensive settlement that PSCo reached with the CPUC Staff and the OCC to increase rates by $12.8 million, to institute the PSIA rider, and to remove gas in underground storage from base rates and recover those costs in the GCA. The GCA is expected to recover another $10 million of annual incremental revenue, subject to adjustment to actual costs. Rates were set on a test year ending June 30, 2011 with an equity ratio of 56 percent and an ROE of 10.1 percent.

New base rates and the GCA recovery went into effect in September 2011. The PSIA rider and new rate designs went into effect on Jan. 1, 2012.

PSCo 2011 Electric Rate Case — In November 2011, PSCo filed a request with the CPUC to increase Colorado retail electric rates by $141.9 million. The request was based on a 2012 forecast test year, a 10.75 percent ROE, a rate base of $5.4 billion and an equity ratio of 56 percent. Final rates are expected to be effective in the summer of 2012. The CPUC is expected to rule on the electric rate case in July 2012.

In November 2011, PSCo filed a petition to implement interim rates, subject to refund, of $100 million to be effective in January 2012. On Jan. 11, 2012, the CPUC denied PSCo's request to implement an interim electric rate increase of $100 million on the basis that it had not demonstrated adverse financial impacts. On Jan. 12, 2012, PSCo filed for reconsideration of the CPUC's decision to deny interim rates, and requested that the CPUC authorize interim rates of approximately $42 million, specifically related to the impacts resulting from the expiration of the Black Hills contract. On Jan. 17, 2012, the CPUC denied the request for reconsideration. However, on Jan. 27, 2012, the CPUC approved PSCo's request for deferred accounting of the $42 million annual revenue requirement associated with the Black Hills contract.

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Pending Regulatory Proceedings — FERC

Base Rate

PSCo Wholesale Electric Rate Case — In February 2011, PSCo filed with the FERC to change Colorado wholesale electric rates to formula based rates with an expected annual increase of $16.1 million for 2011. The request was based on a 2011 forecast test year, a 10.9 percent ROE, a rate base of $407.4 million and an equity ratio of 57.1 percent. The formula rate would be estimated each year for the following year and then trued-up to actual costs after the conclusion of the calendar year. A decision is expected in the first quarter of 2012.

Electric, Purchased Gas and Resource Incentive Adjustment Clauses

PSCo has several retail adjustment clauses that recover fuel, purchased energy, other resource costs, lost margins and/or performance incentives, which are generally recovered concurrently through riders and base rates. At Dec. 31, 2011, pending adjustment clauses, which contain amounts related to incentive programs were as follows:

DSM and the DSMCA — The CPUC approved higher savings goals and a slightly higher financial incentive mechanism for PSCo's electric DSM energy efficiency programs starting in 2012. Savings goals will increase to 130 percent of the current goals and incentives will be awarded as one installment in the year following plan achievements. PSCo will also be able to earn an incentive on 11 percent of net economic benefits at an achievement level of 130 percent and a maximum annual incentive of $30 million.

The CPUC approved the PSCo electric DSM budget of $77.3 million and gas DSM budget of $12.2 million effective Jan. 1, 2012. This is in addition to $29.4 million for electricity demand response programs recovered through the DSMCA. Energy efficiency and demand response related DSM costs are recovered through a combination of the DSMCA riders and base rates. The DSMCA riders are adjusted biannually to capture program costs, performance incentives, and any over- or under-recoveries are trued-up in the following year.

REC Sharing — In May 2011, the CPUC determined that margin sharing on stand-alone REC transactions would be shared 20 percent to PSCo and 80 percent to customers beginning in 2011 and ultimately becoming 10 percent to PSCo and 90 percent to customers by 2014. The CPUC also approved a change to the treatment of hybrid REC trading margins (RECs that are bundled with energy) that allows the customers' share of the margins to be netted against the RESA regulatory asset balance. In the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

In June 2011, PSCo filed an application with the CPUC for permanent treatment of RECs that are bundled with energy into California. The application is seeking margin sharing of 30 percent to PSCo and 70 percent to customers for deliveries outside of California and 40 percent to PSCo and 60 percent to customers for deliveries inside of California. PSCo also proposed that sales of RECs bundled with on-system energy be aggregated with other trading margins and shared 20 percent to PSCo and 80 percent to customers. In September 2011, the CPUC Staff, the OCC, and the Colorado Energy Consumers filed answer testimony requesting the CPUC approve margin sharing of 8 percent to 25 percent to PSCo for deliveries outside of California and 8 percent to 35 percent for deliveries inside of California.

In January 2012, the CPUC approved the margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. All customer margin sharing and unspent carbon offset funds will be credited to the RESA regulatory asset balance. Because the sharing percentage was less than recommended by the CPUC Staff, OCC, and the Colorado Energy Consumers, PSCo plans to file an Application for Rehearing, Reargument and Reconsideration during the first quarter of 2012.

SPS

Recently Concluded Regulatory Proceedings — NMPRC and PUCT

Base Rate

SPS – New Mexico Retail Rate Case — In February 2011, SPS filed a request with the NMPRC seeking to increase New Mexico electric rates approximately $19.9 million. The rate filing was based on a 2011 test year adjusted for known and measurable changes for 2012, a requested ROE of 11.25 percent, an electric rate base of $390.3 million and an equity ratio of 51.11 percent.

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In December 2011, the NMPRC approved a black box settlement with new rates effective Jan. 1, 2012. The settlement increased base rates by $13.5 million. SPS agreed not to file another base rate case until Dec. 3, 2012 with new final rates from the result of such case not going into effect until Jan. 1, 2014 (Settlement Period). However, SPS can request to implement interim rates if the NMPRC standard for interim rates is met. During the Settlement Period, rates are to remain fixed aside from the continued operation of the fuel adjustment clause and certain exceptions for energy efficiency, a rider for an approved renewable portfolio standard regulatory asset, and actual costs incurred for environmental regulations with an effective date after Dec. 31, 2010.

SPS – Texas Retail Rate Case — In May 2010, SPS filed a request with the PUCT seeking to increase Texas electric rates by approximately $71.5 million inclusive of franchise fees. The rate filing was based on a 2009 test year adjusted for known and measurable changes, a requested ROE of 11.35 percent, an electric rate base of $1.031 billion and an equity ratio of 51.0 percent. In November 2010, SPS filed an update to the cost of service to reflect the sale of Lubbock facilities which reduced the total request to approximately $63.7 million.

Effective Feb. 16, 2011, the parties reached an unopposed settlement to resolve all issues in the case and increase base rates by $39.4 million, of which $16.9 million is associated with the transfer of two riders, the TCRF and the PCRF, into base rates. Effective Jan. 1, 2012, base rates increased by an additional $13.1 million.

SPS agreed not to file another rate case until Sept. 15, 2012. In addition, SPS cannot file a TCRF application until 2013, and if SPS files a TCRF application before the effective date of rates in its next rate case, it must reduce the calculated TCRF revenue requirement by $12.2 million.

13. Commitments and Contingent Liabilities

Commitments

Capital Commitments — Xcel Energy has made commitments in connection with a portion of its projected capital expenditures. Xcel Energy's capital commitments primarily relate to the following major projects:

Nuclear Lifecycle Management and Extended Power Uprates — NSP-Minnesota is pursuing improvements to make sure the plants operate safely until the end of their extended licensed life and is making capacity increases of the Monticello and Prairie Island generating plants that could total up to approximately 188 MW. The MPUC approved the CON for the extended power uprate for Monticello in 2008. The license amendment application was filed with the NRC in November 2008, but a concern was raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. In October 2011, the Advisory Committee recommended that all licensing actions that credit the use of containment accident pressure be suspended until the causes and risks of Japan's Fukushima incident are better understood. NSP-Minnesota has rescheduled the remaining equipment changes needed to complete the Monticello power uprate projects during the planned spring 2013 refueling outage.

The MPUC approved an extended power uprate for the Prairie Island Units in 2009. Analysis of recent extended power uprate submittals to the NRC concluded that significant additional design work beyond current schedule and cost plan estimates are now being required to submit a successful application. As a result, NSP-Minnesota is completing an economic and new project design analysis to determine project impacts and anticipates submitting a Change in Circumstances filing with the MPUC in the first quarter of 2012.

CapX2020 — CapX2020 is an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest, including Xcel Energy that have proposed several groups of transmission projects to be complete by 2020. Group 1 project investments consist of four transmission lines. Major construction began in 2010 on the Group 1 transmission lines with an expected completion date in 2015. NSP System's investment depends on the routes and configurations approved by affected state commissions. The remainder of the costs will be born by other utilities in the upper Midwest.

CACJA — The CACJA aims to reduce annual emissions of NOx by at least 70 to 80 percent or greater from 2008 levels by 2017 from the coal fired generation identified in the plan.

CSAPR — CSAPR addresses long range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. CSAPR is discussed further at Environmental Contingencies. Xcel Energy is in the process of determining various scenarios to respond to the CSAPR depending on whether the CSAPR is upheld, reversed, or modified.

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Fuel Contracts — Xcel Energy has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2012 and 2060. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy's risk of loss, in the form of increased costs from market price changes in fuel, is mitigated through the use of natural gas and energy cost-rate adjustment mechanisms, which provide for pass-through of most fuel, storage and transportation costs to customers.

The estimated minimum purchases for Xcel Energy under these contracts as of Dec. 31, 2011 are as follows:

(Millions of Dollars)	Dec. 31, 2011
Coal	$ 3,683
Nuclear fuel	1,546
Natural gas supply	1,122
Natural gas storage and transportation	2,755

Estimated coal requirements at Dec. 31, 2011 have been adjusted to account for Sherco Unit 3, which was shut down in November 2011 after experiencing a significant failure of its turbine, generator and exciter systems. It is uncertain when Sherco Unit 3 will recommence operations. See Note 5 for further discussion.

Purchased Power Agreements — Xcel Energy has entered into agreements with other utilities and energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance or during outages, and meet operating reserve obligations.

NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through 2033. In general, these contracts provide for energy payments based on actual power taken under the contracts, as well as capacity payments. Capacity payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices; however, the effects of price adjustments are mitigated through purchased energy cost recovery mechanisms.

Included in electric fuel and purchased power expenses for purchased power agreements were payments for capacity of $325.3 million, $426.7 million and $461.3 million in 2011, 2010 and 2009, respectively. At Dec. 31, 2011, the estimated future payments for capacity that the utility subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

(Millions of Dollars)	
2012	$275.5
2013	227.2
2014	224.9
2015	198.6
2016	148.7
2017 and thereafter	404.0
Total	$1,478.9

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

Purchased Power Agreements — Under certain purchased power agreements, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities that own natural gas or biomass fueled power plants for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the subsidiaries procure the natural gas required to produce the energy that they purchase. These specific purchased power agreements create a variable interest in the associated independent power producing entity.

Xcel Energy has determined that certain independent power producing entities are variable interest entities. Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is in the future required to be provided other than contractual payments for energy and capacity set forth in the purchased power agreements.

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Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, control over dispatch of electricity, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. Xcel Energy had approximately 3,773 MW and 4,101 MW of capacity under long-term purchased power agreements as of Dec. 31, 2011 and Dec. 31, 2010 with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2033.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO under contracts for those facilities that expire in 2016 and 2017, respectively. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

No significant financial support has been, or is in the future, required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs. SPS has determined that TUCO is a variable interest entity. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

Low-Income Housing Limited Partnerships — Eloigne and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. These limited partnerships are designed to qualify for low-income housing tax credits, and Eloigne and NSP-Wisconsin generally receive a larger allocation of the tax credits than the general partners at inception of the arrangements. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne and NSP-Wisconsin and the general partner of each limited partnership, and Xcel Energy's risk of loss is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is in the future, required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin. Mortgage-backed debt typically comprises the majority of the financing at inception of each limited partnership and is paid over the life of the limited partnership arrangement. Obligations of the limited partnerships are generally secured by the housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy Inc. or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy Inc. or its subsidiaries.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	Dec. 31, 2011	Dec. 31, 2010
Current assets	$ 4,034	$ 3,794
Property, plant and equipment, net	90,914	97,602
Other noncurrent assets	8,053	8,236

Total assets	$ 103,001	$ 109,632
Current liabilities	$ 12,297	$ 11,884
Mortgages and other long-term debt payable	48,863	53,195
Other noncurrent liabilities	8,278	8,333
Total liabilities	$ 69,438	$ 73,412

Leases — Xcel Energy leases a variety of equipment and facilities used in the normal course of business. Three of these leases qualify as capital leases and are accounted for accordingly. The assets and liabilities at the inception of the capital leases are recorded at the lower of fair market value or the present value of future lease payments and are amortized over their actual contract term.

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WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy Inc. has a 50 percent ownership interest in WYCO. WYCO leases the facilities to CIG, and CIG operates the facilities, providing natural gas storage services to PSCo under a service arrangement.

PSCo accounts for its Totem natural gas storage service arrangement with CIG as a capital lease. As a result, PSCo had $152.7 million and $149.9 million of capital lease obligations recorded for the arrangement as of Dec. 31, 2011 and 2010, respectively. Xcel Energy Inc. eliminates 50 percent of the capital lease obligation related to WYCO in the consolidated balance sheet along with an equal amount of Xcel Energy Inc.'s equity investment in WYCO.

PSCo records amortization for its capital leases as cost of natural gas sold and transported on the consolidated statements of income. Total amortization expenses under capital lease assets were approximately $3.2 million, $5.3 million, and $3.5 million for 2011, 2010 and 2009, respectively. Following is a summary of property held under capital leases:

(Millions of Dollars)	2011	2010
Storage, leaseholds and rights	$ 200.5	$ 196.1
Gas pipeline	20.7	20.7
Property held under capital lease	221.2	216.8
Accumulated depreciation	(29.8)	(26.6)
Total property held under capital leases, net	$ 191.4	$ 190.2

The remainder of the leases, primarily for office space, railcars, generating facilities, trucks, aircraft, cars and power-operated equipment, are accounted for as operating leases. Total expenses under operating lease obligations for Xcel Energy were approximately $204.8 million, $197.4 million, and $209.5 million for 2011, 2010 and 2009, respectively. These expenses include payments for capacity recorded to electric fuel and purchased power expenses for purchased power agreements accounted for as operating leases of $160.5 million, $163.7 million, and $171.3 million in 2011, 2010 and 2009, respectively.

Included in the future commitments under operating leases are estimated future payments under purchased power agreements that have been accounted for as operating leases in accordance with the applicable accounting guidance. Future commitments under operating and capital leases are:

(Millions of Dollars)	Other Operating Leases	Purchased Power Agreement Operating Leases (a) (b)	Total Operating Leases	Capital Leases
2012	$ 26.6	$ 159.0	$ 185.6	$ 18.2
2013	24.8	173.5	198.3	18.0
2014	24.3	180.6	204.9	18.0
2015	23.2	182.0	205.2	17.9
2016	18.2	173.9	192.1	17.2
Thereafter	89.6	1,908.7	1,998.3	306.2
Total minimum obligation				395.5
Interest component of obligation				(280.5)
Present value of minimum obligation				$ 115.0 (c)

(a) Amounts do not include purchased power agreements accounted for as other commitments, which are recorded to O&M as executed.

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

(c)Future commitments exclude certain amounts related to Xcel Energy's 50 percent ownership interest in WYCO.

Technology Agreements — Xcel Energy has a contract that extends through Sept. 30, 2015 with IBM for information technology services. The contract is cancelable at Xcel Energy's option, although there are financial penalties for early termination. In 2011, Xcel Energy paid IBM $93.6 million under the contract which included $1.4 million for other project business. In 2010, Xcel Energy paid IBM $95.6 million under the contract which included $2.0 million for other project business.

Xcel Energy's contract with Accenture for information technology services extends through Jan. 31, 2017. It is cancelable at Xcel Energy's option, although Xcel Energy would be obligated to pay 50 percent of the contract value for early termination. In 2011, Xcel Energy paid Accenture $15.2 million under the contract which included $5.6 million for other project business. In 2010, Xcel Energy paid Accenture $22.7 million under the contract which included $8.4 million for other project business.

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Committed minimum payments under these obligations are as follows:

(Millions of Dollars)	IBM Agreement	Accenture Agreement
2012	$19.2	$8.7
2013	17.6	8.4
2014	17.2	8.2
2015	11.9	8.2
2016 and thereafter	-	8.1

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Dec. 31, 2011, Xcel Energy Inc. and its subsidiaries have no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

Guarantees and Surety Bonds

The following table presents guarantees and bond indemnities issued and outstanding, including those guarantees related to Xcel Energy Wholesales Group Inc., Seren, UE, Viking, and Xcel Energy Argentina Inc., which are components of discontinued operations, as of Dec. 31, 2011:

(Millions of Dollars)	Guarantor	Guarantee Amount	Current Exposure	Triggering Event
Guarantee of the indemnification obligations of Xcel Energy Wholesale Group Inc. under a stock purchase agreement (e)	Xcel Energy Inc.	$ 17.5	$ 17.5	(b)
Guarantee of the indemnification obligations of Xcel Energy Argentina Inc. under a stock purchase agreement (d)	Xcel Energy Inc.	14.7	—	(b)
Guarantee of the indemnification obligations of various Xcel Energy Inc. subsidiaries under different asset purchase agreements (d)	Xcel Energy Inc.	25.5	—	(b)
Guarantee of customer loans for the Farm Rewiring Program (f)	NSP-Wisconsin	1.0	0.5	(c)
Guarantee of the indemnification obligations of Xcel Energy Services Inc. under the aircraft leases (g)	Xcel Energy Inc.	8.3	—	(a)
Guarantee benefiting Young Gas Storage Company Ltd. (f)	Xcel Energy Inc.	0.5	—	(a)
Total guarantees issued		$ 67.5	$ 18.0	

Guarantee performance and payment of surety bonds for Xcel Energy Inc. and its subsidiaries (j) (k)	Xcel Energy Inc.	$ 31.2	(h)	(i)

(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) The debtor becomes the subject of bankruptcy or other insolvency proceedings.
(d) The term of this guarantee is continuing. Certain representations and warranties relating to due organization, transaction authorization and tax matters survive indefinitely. As of Dec. 31, 2011, no claims have been made.
(e) The indemnification provisions of the guarantee expired in 2010. As of Dec. 31, 2011, there is a pending indemnification claim causing the guarantee liability to remain outstanding until the final resolution.
(f) The term of this guarantee is continuing.
(g) The term of this guarantee expires in 2012 when the associated leases expire. At the time of renewal of the aircraft leases, the related guarantees will also be renewed.
(h) Due to the magnitude of projects associated with the surety bonds, the total current exposure of this indemnification cannot be determined. Xcel Energy Inc. believes the exposure to be significantly less than the total amount of the outstanding bonds.
(i) Failure of Xcel Energy Inc. 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 Inc. and the various surety companies, the surety companies have the discretion to demand that collateral be posted.
(j) Xcel Energy Inc. has on ongoing agreement to indemnify an insurance company in connection with surety bonds they may issue or have issued for UE up to $80 million. Xcel Energy Inc.'s indemnification will be triggered only in the event that UE has failed to meet its obligations to the surety company.
(k) The expiration date of the surety bonds is project based. Accordingly, the surety bonds expire in conjunction with the completion of the related projects.

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Indemnification Agreements

In connection with the purchase and sale agreement of certain electric distribution assets in Lubbock, Texas, SPS agreed to indemnify the purchaser for losses arising out of any breach of the representations, warranties and covenants under the related asset purchase agreement and for losses arising out of certain other matters, including pre-closing unknown liabilities. SPS' indemnification obligation is capped at $87 million, in the aggregate. The indemnification provisions for most representations and warranties expired in October 2011. The remaining representations and warranties, which relate to due organization and transaction authorization, survive indefinitely. SPS has not recorded a liability related to this indemnity.

In connection with the acquisition of the 201 MW Nobles wind project, NSP-Minnesota agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. NSP-Minnesota's indemnification obligation is capped at $20 million, in the aggregate. The indemnification obligation expires in March 2013. NSP-Minnesota has not recorded a liability related to this indemnity.

In connection with the acquisition of 900 MW of gas-fired generation from subsidiaries ofCalpine Development Holdings Inc., PSCo agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. The aggregate liability for PSCo pursuant to these indemnities is not subject to a capped dollar amount. The indemnification obligation expires in December 2012. PSCo has not recorded a liability related to this indemnity.

Xcel Energy Inc. and its subsidiaries provide other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including due organization, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of time and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

Xcel Energy has been or is currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other PRPs and through the regulated rate process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy, which are normally recovered through the regulated rate process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation — The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and other comparable federal and state environmental laws impose liability, without regard to the legality of the original conduct, on certain classes of persons where hazardous substances or other regulated materials have been released to the environment. Xcel Energy Inc.'s subsidiaries may sometimes pay all or a portion of the cost to remediate sites where past activities of their predecessors or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former MGPs operated by Xcel Energy Inc.'s subsidiaries or their predecessors, or other entities; and third-party sites, such as landfills, for which one or more of Xcel Energy Inc.'s subsidiaries are alleged to be a PRP that sent hazardous materials and wastes to that site.

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The EPA issued its Record of Decision (ROD) in September 2010, which documents the remedy that the EPA has selected for the cleanup of the Ashland site. In April 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future cleanup at the site. The special notice letters requested that those PRPs participate in negotiations with the EPA regarding how the PRPs intend to conduct or pay for the cleanup. On June 30, 2011, NSP-Wisconsin submitted a settlement offer to the EPA related to the future cleanup of the Ashland site. On July 14, 2011, the EPA informed NSP-Wisconsin and the other PRPs that it was rejecting all of their individual offers and can now choose to initiate enforcement actions at any time. Despite this decision, the EPA also indicated a willingness to continue settlement negotiations with NSP-Wisconsin. Settlement negotiations are ongoing.

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At Dec. 31, 2011 and Dec. 31, 2010, NSP-Wisconsin had recorded a liability of $104.3 million and $97.5 million, respectively, based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $26.6 million and $4.8 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change until after negotiations or litigation with the EPA and other PRPs are fully resolved. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include, but are not limited to, the cleanup approach implemented, which party implements the cleanup, the timing of when the cleanup is implemented and the contributions, if any, by other PRPs.

NSP-Wisconsin has deferred, as a regulatory asset, the estimated site remediation expenses and spending to date less insurance and rate recoveries, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process. Under an existing PSCW policy with respect to recovery of remediation costs for MGPs, utilities have recovered remediation costs in natural gas rates, amortized over a four- to six-year period. The PSCW has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation. In a recent rate case decision, the PSCW recognized the potential magnitude of the future liability for, and circumstances of, the cleanup at the Ashland site and indicated it may consider alternatives to its established MGP site cleanup cost accounting and cost recovery guidelines for the Ashland site in a future proceeding. NSP-Wisconsin is working with the PSCW Staff to develop alternatives for consideration by the PSCW.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where hazardous or other regulated materials may have been deposited. Xcel Energy has identified 8 sites, where former MGP activities have or may have resulted in actual site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any ultimate remediation that may be conducted. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2014. For these sites, Xcel Energy had accrued $3.9 million and $3.2 million at Dec. 31, 2011 and Dec. 31, 2010, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs actually incurred at these sites. Xcel Energy anticipates that any amounts actually spent will be fully recovered from customers.

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. Xcel Energy has recorded an estimate for final removal of the asbestos as an ARO. See additional discussion of AROs below. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA GHG Regulation — In December 2009, the EPA issued its "endangerment" finding that GHG emissions pose a threat to public health and welfare. In January 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which are applicable to the construction of new power plants or power plant modifications that increase emissions above a certain threshold. Xcel Energy is unable to determine what the cost of compliance with these new EPA requirements will be as it is not clear whether these requirements will apply to futures changes at Xcel Energy's power plants.

New Mexico GHG Regulations — In 2010, the EIB adopted two regulations to limit GHG emissions, including CO_2 emissions from power plants and other industrial sources. SPS, other utilities and industry groups have filed separate appeals with the New Mexico Court of Appeals challenging the validity of these two GHG regulations. The appellate cases have been stayed pending further proceedings before the EIB.

In July 2011, SPS and other parties filed a petition for repeal of each state GHG rule with the EIB. The EIB held hearings for both repeal petitions in 2011. The first of these two regulations was repealed by the EIB in February 2012. The second will be reviewed in March 2012. Unless repealed, the second rule is scheduled to become applicable to SPS beginning in 2013. Efforts to quantify compliance costs have been suspended pending the outcome on the second rule.

GHG New Source Performance Standard Proposal — The EPA plans to propose GHG regulations applicable to emissions from new and existing power plants under the CAA. The EPA had planned to release its proposal in September 2011, but has delayed it without establishing a new proposal date.

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CSAPR — In July 2011, the EPA issued its CSAPR to address long range transport of particulate matter and ozone by requiring reductions in SO2 and NOx from utilities located in the eastern half of the U.S. For Xcel Energy, the rule applies to Minnesota, Wisconsin and Texas. The CSAPR sets more stringent requirements than the proposed CATR and, in contrast to that proposal, specifically requires plants in Texas to reduce their SO2 and annual NOx emissions. The rule also creates an emissions trading program. Xcel Energy intends to comply by reducing emissions and/or purchasing allowances.

On Dec. 30, 2011, the U.S. Court of Appeals for the D.C. Circuit issued a stay of the CSAPR, pending completion of judicial review. The Court is expected to hear the case in April 2012. Xcel Energy anticipates that the court may rule on the challenges to the CSAPR in the second half of 2012. It is not known at this time whether the CSAPR will be upheld, reversed or will require modifications pursuant to a future Court decision.

If the CSAPR is upheld and unmodified, Xcel Energy believes that the CSAPR could ultimately require the installation of additional emission controls on some of SPS' coal-fired electric generating units. If compliance is required in a short time frame, SPS may be required to redispatch its system to reduce coal plant operating hours, in order to decrease emissions from its facilities prior to the installation of emission controls. The expected cost for these scenarios may vary significantly and SPS has estimated capital expenditures of approximately $470 million over the next four years for the plant modifications related to the CSAPR requirements. SPS believes the cost of any required capital investment or possible increased fuel costs would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position or cash flows.

If the CSAPR is upheld and unmodified, NSP-Minnesota would likely utilize a combination of emissions reductions through upgrades to its existing SO2 control technology at NSP-Minnesota's Sherco plant, which is estimated to cost a total of $10 million through 2014, and system operating changes to the Black Dog and the Sherco plants. If available, NSP-Minnesota would also consider allowance purchases. In addition, NSP-Minnesota has filed a petition for reconsideration with the EPA and a petition for review of the CSAPR with the U.S. Court of Appeals for the D.C. Circuit seeking the allocation of additional emission allowances to NSP-Minnesota. NSP-Minnesota contends that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. If successful, additional allowances would reduce NSP-Minnesota's costs to comply with the reductions that may be imposed by the CSAPR.

If the CSAPR is upheld and unmodified, NSP-Wisconsin would likely make a combination of system operating changes and allowance purchases. NSP-Wisconsin estimates the cost of compliance would be $0.2 million, and expects the cost of any required capital investment will be recoverable from customers.

CAIR — In 2005, the EPA issued the CAIR to further regulate SO2 and NOx emissions. The CAIR applies to Texas and Wisconsin. The CAIR does not currently apply in Minnesota because the Court specifically found that the EPA had not adequately justified the application of the CAIR to Minnesota. In granting the stay of the CSAPR, the Court specifically noted that the CAIR would remain in place during its pending review of the CSAPR.

Under the CAIR's cap and trade structure, companies can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. To comply with the CAIR in 2012, NSP-Wisconsin will likely make a combination of system operating changes and allowance purchases, if available. In the SPS region, installation of low-NOx combustion control technology began on Tolk Unit 1 in January 2012. Installation will begin on Tolk Unit 2 at a yet to be determined date. These installations will reduce or eliminate SPS' need to purchase NOx emission allowances. In addition, SPS has sufficient SO2 allowances to comply with CAIR in 2012. At Dec. 31, 2011, the estimated annual CAIR NOx allowance cost for Xcel Energy does not have a material impact on the results of operations, financial position or cash flows.

EGU Mercury and Air Toxics Standards (MATS) Rule — In December 2011, the EPA issued the final EGU MATS rule to replace the proposed EGU MACT rule. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and will require coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years. Xcel Energy believes these costs would be recoverable through regulatory mechanisms, and it does not expect a material impact on its results of operations, financial position or cash flows.

Colorado Mercury Regulation — Colorado's mercury regulations require mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by the end of 2011. The cost for the Pawnee Generating Station mercury controls was $1.1 million for capital costs with an annual estimate of $0.5 million for sorbent expense. PSCo has evaluated the Colorado mercury control requirements for its other units in Colorado and believes that, under the current regulations, no further controls will be required other than the planned controls at the Pawnee Generating Station, which are included in the CACJA compliance plan.

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Minnesota Mercury Legislation — Under the 2006 mercury legislation, NSP-Minnesota installed sorbent control systems at the Sherco Unit 3 and A.S. King generating plants, with project costs collected through the MCR rider in 2010. Subsequently, in the 2010 Minnesota electric rate case, the costs of these projects were moved into base rates as part of the interim rates effective Jan. 2, 2011. NSP-Minnesota has also obtained MPUC approval to install mercury controls on Sherco Units 1 and 2 by the end of 2014.

For Sherco Units 1 and 2, NSP-Minnesota has incurred $1.5 million in study costs to date and spent $0.6 million through Dec. 31, 2011 for testing and studying of technologies. At Dec. 31, 2011, the estimated annual testing and study cost is $0.5 million. NSP-Minnesota projects installation costs of $12.0 million for the mercury controls on the units and O&M expense of $10.0 million per year beginning in 2014. NSP-Minnesota believes these costs would be recoverable through regulatory mechanisms.

Industrial Broiler (IB) MACT Rules — In March 2011, the EPA finalized IB MACT rules to regulate boilers and process heaters fueled with coal, biomass and liquid fuels, which would apply to NSP-Wisconsin's Bay Front units 1 and 2. On Dec. 23, 2011, the EPA proposed reconsideration of certain provisions of the final rule. The estimated capital cost of $9.0 million per unit, which is currently targeted for 2014, is dependent on the outcome of the reconsideration proceedings.

Colorado Proposed Surface Impoundment Regulations (Section 9) — In February 2012, the Colorado Department of Public Health and the Environment promulgated new solid waste regulations that establish new design and operating requirements for surface impoundments, including coal ash ponds and cooling tower ponds. The regulations provide a partial exemption on design upgrades for coal ash ponds pending a final Coal Combustion Residuals Rule from EPA. The final rule also exempts PSCo's ponds that will be closed under the CACJA. The effective date will be March 30, 2012. Estimated costs for compliance are approximately $18 million in total through 2018.

Regional Haze Rules — In 2005, the EPA finalized amendments to its regional haze rules regarding provisions that require the installation and operation of emission controls, known as BART, for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas throughout the U.S. Xcel Energy generating facilities in several states will be subject to BART requirements. Individual states are required to identify the facilities located in their states that will have to reduce SO2, NOx and particulate matter emissions under BART and then set emissions limits for those facilities.

PSCo

In 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate, install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. In January 2011, the Colorado Air Quality Control Commission approved a revised Regional Haze BART SIP incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. The Colorado SIP is currently pending before the EPA. PSCo expects the cost of any required capital investment will be recoverable from customers through the CACJA plan recovery mechanisms or other regulatory mechanisms. Emissions controls are expected to be installed between 2012 and 2017. The costs associated with the CACJA plan are discussed in Capital Commitments.

In March 2010, two environmental groups petitioned the U.S. DOI to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. Four PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege that the Colorado BART rule is inadequate to satisfy the CAA mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota

In December 2009, the MPCA Citizens Board approved the Regional Haze SIP, which has been submitted to the EPA for approval. The MPCA selected the BART controls for Sherco Units 1 and 2 to improve visibility in the national parks. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The MPCA's BART controls for Sherco Units 1 and 2 consist of combustion controls for NOx and scrubber upgrades for SO2. The combustion controls have been installed on Sherco Units 1 and 2, and the scrubber upgrades are scheduled to be installed by 2015. At this time, the estimated cost for meeting the BART and other CAA requirements is approximately $50 million of which $20 million has already been spent on projects to reduce NOx emissions on Sherco Units 1 and 2. Xcel Energy anticipates that all costs associated with BART compliance will be fully recoverable.

In June 2011, the EPA provided comments to the MPCA on the SIP, stating the EPA's preliminary review indicates that SCR controls should be added to Sherco Units 1 and 2. The MPCA has since proposed that the CSAPR should be considered BART for EGUs and the EPA has proposed that states be allowed to find that CSAPR compliance meets BART requirements for EGUs, and specifically that Minnesota's proposal to find the CSAPR to meet BART requirements should be approved, if finalized by the state. It is not yet known what the final requirements will be. NSP-Minnesota does not expect that a finding that the CSAPR meets BART requirements would result in changes to the control equipment plans described above, and has requested that the MPCA retain its 2009 BART determination.

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In October 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to visibility impairment and, if so, whether the level of controls proposed by the MPCA is appropriate. In its Jan. 25, 2012 notice concerning its review of Minnesota's Regional Haze SIP, the EPA noted that it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the Reasonably Attributable Visibility Impairment (RAVI) program. It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail.

SPS
Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a Regional Haze SIP that finds the CAIR equal to BART for EGUs, and as a result, no additional controls for these units beyond the CAIR compliance, described above are required.

Federal Clean Water Act (CWA) Section 316 (b) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. In April 2011, the EPA published the proposed rule that sets prescriptive standards for minimization of aquatic species impingement, but leaves entrainment reduction requirements at the discretion of the permit writer and the regional EPA office. Xcel Energy provided comments to the proposed rule, which is expected to be finalized in late 2012. Due to the uncertainty of the final regulatory requirements, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

As part of NSP-Minnesota's 2009 CWA permit renewal for the Black Dog plant, the MPCA required the submission of a plan for compliance with the CWA. The compliance plan was submitted for MPCA review and approval in April 2010. The MPCA is currently reviewing the proposal in consultation with the EPA.

Proposed Coal Ash Regulation — Xcel Energy's operations generate hazardous wastes that are subject to the Federal Resource Recovery and Conservation Act and comparable state laws that impose detailed requirements for handling, storage, treatment and disposal of hazardous waste. In June 2010, the EPA published a proposed rule seeking comment on whether to regulate coal combustion byproducts (coal ash) as hazardous or nonhazardous waste. Coal ash is currently exempt from hazardous waste regulation. If the EPA ultimately issues a final rule under which coal ash is regulated as hazardous waste, Xcel Energy's costs associated with the management and disposal of coal ash would significantly increase and the beneficial reuse of coal ash would be negatively impacted. The EPA has not announced a planned date for a final rule. The timing, scope and potential cost of any final rule that might be implemented are not determinable at this time.

PSCo NOV — In 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Generating Station in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid to late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Cunningham Compliance Order — In December, 2011, SPS entered into a final agreement with the NMED that resolved allegations that Cunningham exceeded its permit limits for NOx and failed to report these exceedances as required by its permit. The settlement was \$0.8 million.

NSP-Minnesota NOV — In June 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the NSR requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid 2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also 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. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

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Asset Retirement Obligations

Recorded AROs — AROs have been recorded for plant related to nuclear production, steam production, wind production, electric transmission and distribution, natural gas transmission and distribution and office buildings. The steam production obligation includes asbestos, ash-containment facilities, radiation sources and decommissioning. The asbestos recognition associated with the steam production includes certain plants at NSP-Minnesota, PSCo and SPS. NSP-Minnesota also recorded asbestos recognition for its general office building. This asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota, PSCo and SPS steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination dates on the ARO recognition for ash-containment facilities at steam plants was the in-service dates of the various facilities. Additional AROs have been recorded for NSP-Minnesota and PSCo steam production plant related to radiation sources in equipment used to monitor the flow of coal, lime and other materials through feeders.

Xcel Energy recognized an ARO for the retirement costs of natural gas mains at NSP-Minnesota, NSP-Wisconsin and PSCo. In addition, an ARO was recognized for the removal of electric transmission and distribution equipment at NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have many in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the ARO associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originated with the in-service date of the facility. See Note 14 for further discussion of nuclear obligations.

A reconciliation of the beginning and ending aggregate carrying amounts of Xcel Energy's AROs is shown in the table below for the years ended Dec. 31, 2011 and Dec. 31, 2010:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2011	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates		Ending Balance Dec. 31, 2011
Electric plant							
Steam production asbestos	$ 93,629	$ -	$ (514)	$ 5,958	$ (44,731)		$ 54,342
Steam production ash containment	19,688	-	-	919	20,551		41,158
Steam production radiation sources	166	-	-	12	(39)		139
Nuclear production decommissioning	809,474	-	-	57,641	615,626	(a)	1,482,741
Wind production	38,553	-	-	1,962	-		40,515
Electric transmission and distribution	5,727	-	-	290	24,687		30,704
Natural gas plant							
Gas transmission and distribution	996	-	-	63	-		1,059
Common and other property							
Common general plant asbestos	1,077	-	-	58	-		1,135

Total liability	$ 969,310	$ -	$ (514)	$ 66,903	$ 616,094	$ 1,651,793

(a) The increase is primarily due to the completion of NSP-Minnesota's triennial nuclear decommissioning study, which reflects an increase in the estimated cost of retirement, increase in the escalation rates for each nuclear unit and a decrease in the discount rate used to calculate the net present value of the future cash flows.

The fair value of NSP-Minnesota's legally restricted assets, for purposes of settling the nuclear ARO, was $1.3 billion as of Dec. 31, 2011, including external nuclear decommissioning investment funds and internally funded amounts.

In 2011, revisions were made for nuclear, asbestos, ash-containment facilities, radiation sources and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

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(Thousands of Dollars)	Beginning Balance Jan. 1, 2010	Liabilities Recognized	Liabilities Settled	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2010
Electric plant						
Steam production asbestos	$ 95,093	$ 3,771	$ (2,330)	$ 6,037	$ (8,942)	$ 93,629
Steam production ash containment	17,552	32	-	903	1,201	19,688
Steam production radiation sources	176	-	-	12	(22)	166
Nuclear production decommissioning	758,923	-	-	50,551	-	809,474
Wind production	7,751	25,671	-	592	4,539	38,553
Electric transmission and distribution	27	-	-	12	5,688	5,727
Natural gas plant						
Gas transmission and distribution	936	-	-	60	-	996
Common and other property						
Common general plant asbestos	1,021	-	-	56	-	1,077
Total liability	$ 881,479	$ 29,474	$ (2,330)	$ 58,223	$ 2,464	$ 969,310

The fair value of NSP-Minnesota's legally restricted assets, for purposes of settling the nuclear ARO, was $1.4 billion as of Dec. 31, 2010, including external nuclear decommissioning investment funds and internally funded amounts.

In 2010, revisions were made for asbestos, ash-containment facilities, wind turbines, radiation sources and electric transmission and distribution asset retirement obligations due to revised estimates and end of life dates.

Indeterminate AROs — PSCo has underground natural gas storage facilities that have special closure requirements for which the final removal date cannot be determined; therefore, an ARO has not been recorded.

Removal Costs — Xcel Energy records a regulatory liability for the plant removal costs of other generation, transmission and distribution facilities of its utility subsidiaries. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over 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.

The accumulated balances by entity were as follows at Dec. 31:

(Millions of Dollars)	2011	2010
NSP-Minnesota	$ 382	$ 400
NSP-Wisconsin	109	107
PSCo	380	385
SPS	74	88
Total Xcel Energy	$ 945	$ 980

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Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to $12.6 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured $375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $12.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $117.5 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $17.5 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective April 2010.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $2.25 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $15.7 million for business interruption insurance and $33.6 million for property damage insurance if losses exceed accumulated reserve funds.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material effect on Xcel Energy's financial position and results of operations.

Environmental Litigation

State of Connecticut vs. Xcel Energy Inc. et al. — In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against the following utilities, including Xcel Energy, to force reductions in CO2 emissions: American Electric Power Co., Southern Co., Cinergy Corp. (merged into Duke Energy Corporation) and Tennessee Valley Authority. The lawsuits alleged that CO2 emitted by each company is a public nuisance and asked the court to order each utility to cap and reduce its CO2 emissions. The lawsuits did not demand monetary damages. In December 2011, the U.S. District Court entered an order dismissing this lawsuit, bringing a close to this litigation.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utility, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO2 and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss in June 2008. In October 2009, the U.S. District Court dismissed the lawsuit on constitutional grounds. In November 2009, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit. In November 2011, oral arguments were presented. It is unknown when the Ninth Circuit will render a final opinion. The amount of damages claimed by plaintiffs is unknown, but likely includes the cost of relocating the village of Kivalina. Plaintiffs' alleged relocation is estimated to cost between

$95 million to $400 million. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it may have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Comer vs. Xcel Energy Inc. et al. — On May 27, 2011, less than a year after their initial lawsuit was dismissed, plaintiffs in this purported class action lawsuit filed a second lawsuit against more than 85 utility, oil, chemical and coal companies in U.S. District Court in Mississippi. The complaint alleges defendants' CO_2 emissions intensified the strength of Hurricane Katrina and increased the damage plaintiffs purportedly sustained to their property. Plaintiffs base their claims on public and private nuisance, trespass and negligence. Among the defendants named in the complaint are Xcel Energy Inc., SPS, PSCo, NSP-Wisconsin and NSP-Minnesota. The amount of damages claimed by plaintiffs is unknown. The defendants, including Xcel Energy Inc., believe this lawsuit is without merit and have filed a motion to dismiss the lawsuit. It is uncertain when the court will rule on this motion. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it may have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

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Employment, Tort and Commercial Litigation

Stone & Webster, Inc. vs. PSCo — In July 2009, Stone & Webster, Inc. (Shaw) filed a complaint against PSCo in State District Court in Denver, Colo. for damages allegedly arising out of its construction work on the Comanche Unit 3 coal-fired plant. Shaw, a contractor retained to perform certain engineering, procurement and construction work on Comanche Unit 3, alleged, among other things, that PSCo mismanaged the construction of Comanche Unit 3. Shaw further claimed that this alleged mismanagement caused delays and damages. The complaint also alleged that Xcel Energy Inc. and related entities guaranteed Shaw $10 million in future profits under the terms of a 2003 settlement agreement. In total, Shaw sought approximately $144 million in damages.

In August 2009, PSCo filed an answer and counterclaim denying the allegations in the complaint and alleging that Shaw failed to discharge its contractual obligations and caused delays, and that PSCo is entitled to liquidated damages and excess costs incurred of approximately $82 million.

Following a November 2010 jury trial and subsequent appeal, in November 2011, a confidential settlement was reached dismissing all actions. This settlement did not have a material effect on Xcel Energy's consolidated results of operations, cash flows or financial position.

Merricourt Wind Project Litigation — On April 1, 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. As a result, NSP-Minnesota recorded a $101 million deposit in the first quarter 2011, which was collected in April 2011. On May 5, 2011, NSP-Minnesota filed a declaratory judgment action in U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements. On that same day, enXco also filed a separate lawsuit in the same court seeking, among other things, in excess of $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit and has filed a motion to dismiss. On Sept. 16, 2011, the U.S. District Court denied the motion to dismiss. The trial is set to begin in late 2012 or early 2013. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it may have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Other Contingencies

See Note 12 for further discussion.

14. Nuclear Obligations

Fuel Disposal — NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota's nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE's permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per KWh sold to customers from nuclear generation. Fuel expense includes the DOE fuel disposal assessments of approximately $11 million in 2011, $13 million in 2010 and $12 million in 2009. In total, NSP-Minnesota had paid approximately $422.3 million to the DOE through Dec. 31, 2011. The Nuclear Waste Policy Act of 1982 required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. 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. In 2011, NSP-Minnesota received from the DOE pursuant to a Settlement with the DOE, an initial payment of approximately $100 million to cover damages through the end of 2008. As of Dec. 31, 2011, NSP-Minnesota has recorded the payment as restricted cash and a regulatory liability.

NSP-Minnesota has its own temporary on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants, which consist of storage pools and dry cask facilities at both sites. The amount of spent fuel storage capacity currently authorized by the NRC and the MPUC will allow NSP-Minnesota to continue operation of its Prairie Island nuclear plant until the end of its renewed licenses terms in 2033 for Unit 1 and 2034 for Unit 2 and its Monticello nuclear plant until the end of its renewed operating license in 2030. Other alternatives for spent fuel storage are being investigated until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities.

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Regulatory Plant Decommissioning Recovery — Decommissioning of NSP-Minnesota's nuclear facilities is planned for the period from cessation of operations through at least 2067, assuming the prompt dismantlement method. NSP-Minnesota is currently recording the regulatory costs for decommissioning over the MPUC-approved cost-recovery period and including the accruals in a regulatory liability account. The total decommissioning cost obligation is recorded as an ARO in accordance with the applicable accounting guidance.

Monticello received its initial operating license in 1970 and began commercial operation in 1971. With its renewed operating license and CON for spent fuel capacity to support 20 years of extended operation, Monticello can operate until 2030. The Monticello 20-year depreciation life extension until September 2030 was granted by the MPUC in 2007. Construction of the Monticello dry-cask storage facility is complete, and 10 of the 30 canisters authorized have been filled and placed in the facility.

Prairie Island Units 1 and 2 received their initial operating license and began commercial operations in 1973 and 1974. In April 2008, NSP-Minnesota filed an application with the NRC to renew the operating license of its two nuclear reactors at Prairie Island that allowed for operation for an additional 20 years until 2033 and 2034, respectively. The NRC approved Prairie Island's license renewal application in 2011. Based on the NRC approval, a full life extension for Prairie Island's depreciation life was approved by the MPUC in September 2011, bringing the depreciation remaining life in line with the NRC approved operating license. The Prairie Island dry-cask storage facility currently stores 29 casks, with MPUC approval for the use of 35 additional casks, to support operations until the end of the renewed operating licenses in 2033 and 2034.

The total obligation for decommissioning currently is expected to be funded 100 percent by the external decommissioning trust fund, as approved by the MPUC, when decommissioning commences. The MPUC last approved NSP-Minnesota's nuclear decommissioning study request in October 2009, using 2008 cost data. An updated nuclear decommissioning study was submitted to the MPUC in both November and December 2011. Due to new state statute requirements, five decommissioning scenarios were presented, which each reflected a different timeline for the removal of spent nuclear fuel from the sites. A decision on this filing is expected either in late 2012 or the beginning of 2013.

Consistent with cost-recovery in utility customer rates, NSP-Minnesota previously recorded 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. The most recent study, which resulted in an authorization of no funding, presumes that costs will escalate in the future at a rate of 2.89 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by the external decommissioning trust fund, 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 6.3 percent, net of tax, for external funding. The net unrealized gain or loss on nuclear decommissioning investments is deferred as a regulatory asset or liability, respectively.

The external funds are held in trust and in escrow. The portion in escrow is subject to refund if approved by the various commissions. The MPUC authorized the return of funds associated with the Monticello plant for the Minnesota retail jurisdictions in 2009, with refunds made on customers' bills in 2010. An amount of approximately $5.9 million was also withdrawn from the Monticello plant portion of the escrow fund in March 2010 in preparation for a refund to Wisconsin and Michigan retail customers. The funds have not yet been refunded as of Dec. 31, 2011, and the timing of the refunds will be determined in future rate cases in each jurisdiction.

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At Dec. 31, 2011, NSP-Minnesota recorded and recovered in rates cumulative decommissioning expense of $1.3 billion. The following table summarizes the funded status of NSP-Minnesota's decommissioning obligation based on approved regulatory recovery parameters from the most recently approved decommissioning study. Xcel Energy believes future decommissioning cost expense, if necessary, will continue to be recovered in customer rates. These amounts are not those recorded in the financial statements for the ARO.

	Regulatory Basis	
(Thousands of Dollars)	2011	2010
Estimated decommissioning cost obligation (2008 dollars)	$2,308,196	$2,308,196
Effect of escalating costs (to 2011 and 2010 dollars, respectively, at 2.89 percent per year)	205,960	135,342
Estimated decommissioning cost obligation (in current dollars)	2,514,156	2,443,538
Effect of escalating costs to payment date (2.89 percent per year)	2,602,207	2,672,825
Estimated future decommissioning costs (undiscounted)	5,116,363	5,116,363
Effect of discounting obligation (using risk-free interest rate)	(3,187,914)	(3,856,516)
Discounted decommissioning cost obligation	1,928,449	1,259,847
Assets held in external decommissioning trust	1,336,431	1,350,630
Underfunding (overfunding) of external decommissioning fund compared to the discounted decommissioning obligation	$592,018	$(90,783)

Decommissioning expenses recognized as a result of regulation include the following components:

(Thousands of Dollars)	2011	2010	2009
Annual decommissioning recorded as depreciation expense: (a)			
Externally funded	$-	$934	$2,849
Internally funded (including interest costs)	(456)	(777)	(884)
Net decommissioning expense recorded	$(456)	$157	$1,965

(a)Decommissioning expense does not include depreciation of the capitalized nuclear asset retirement costs.

Reductions to expense for internally-funded portions in 2011, 2010 and 2009 are a direct result of the 2008 decommissioning study jurisdictional allocation and 100 percent external funding approval, effectively unwinding the remaining internal fund over the previously licensed operating life of the unit (2010 for Monticello, 2013 for Prairie Island Unit 1 and 2014 for Prairie Island Unit 2). The 2008 nuclear decommissioning filing approved in 2009 has been used for the regulatory presentation.

15. Regulatory Assets and Liabilities

Xcel Energy Inc. and subsidiaries prepare their consolidated financial statements in accordance with the applicable accounting guidance, as discussed in Note 1. Under this guidance, regulatory assets and liabilities are 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 establish regulatory assets and liabilities. If changes in the utility industry or the business of Xcel Energy no longer allow for the application of regulatory accounting guidance under GAAP, Xcel Energy would be required to recognize the write-off of regulatory assets and liabilities in net income or OCI.

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The components of regulatory assets and liabilities shown on the consolidated balance sheets at Dec. 31, 2011 and Dec. 31, 2010 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2011		Dec. 31, 2010	
Regulatory Assets			Current	Noncurrent	Current	Noncurrent
Pension and retiree medical obligations (a)	9	Various	$ 130,764	$ 1,299,399	$ 115,218	$ 1,209,879
Recoverable deferred taxes on AFUDC recorded in plant (b)	1	Plant lives	-	294,549	-	276,861
Contract valuation adjustments (c)	1, 11	Term of related contract	73,608	142,210	45,155	134,027
Net AROs (d)	1, 13, 14	Plant lives	-	209,626	-	150,913
Conservation programs (e)	1	One to seven years	46,769	80,981	57,679	74,236
Environmental remediation costs	1, 13	Various	2,309	109,720	3,561	98,725
Renewable resources and environmental initiatives (b)	13	One to four years	51,622	25,378	75,372	20,487
Depreciation differences (b)	1	One to seven years	4,150	54,892	5,859	12,379
Purchased power contract costs	13	Term of related contract	-	54,471	-	44,464
Losses on reacquired debt	4	Term of related debt	5,554	43,729	6,319	49,001
Nuclear refueling outage costs	1	One to two years	40,365	8,810	33,819	7,169
Gas pipeline inspection and remediation costs	12	Pending rate case	13,779	27,511	2,000	29,358
Recoverable purchased natural gas and electric energy costs	1	One to two years	17,031	9,867	27,770	9,907
State commission adjustments (b)	1	Plant lives	311	9,399	-	9,235
Other		Various	15,973	18,466	15,789	24,819
Total regulatory assets			$ 402,235	$ 2,389,008	$ 388,541	$ 2,151,460
Regulatory Liabilities						
Plant removal costs	1, 13	Plant lives	$ -	$ 945,377	$ -	$ 979,666
Deferred electric, gas and steam production costs	1	Less than one year	108,057	-	107,674	-
DOE settlement	14	Less than one year	94,734	-	-	-
Investment tax credit deferrals	1, 6	Various	-	61,710	-	65,856
	1, 6	Various	-	46,835	-	42,863

Deferred income tax adjustment						
Conservation programs (e)	1, 12	Less than one year	15,898	-	-	-
Contract valuation adjustments (c)	1, 11	Term of related contract	25,268	15,450	6,684	19,743
Gain from asset sales	18	One to three years	5,780	18,696	4,281	25,492
Renewable resources and environmental initiatives (b)	12, 13	Various	4,358	8,525	14,752	-
Low income discount program		One to two years	8,696	347	7,062	4,032
Nuclear refueling outage costs	1	One year	3,441	-	3,441	3,441
REC margin sharing (f)	1, 12		-	-	-	26,104
Other		Various	8,863	4,594	12,144	12,568
Total regulatory liabilities			$ 275,095	$ 1,101,534	$ 156,038	$ 1,179,765

(a) Includes $365.3 million and $400.2 million for the regulatory recognition of the NSP-Minnesota pension expense at Dec. 31, 2011 and Dec. 31, 2010, respectively. These amounts are offset by $3.9 million and $7.8 million for PSCo unamortized prior service costs at Dec. 31, 2011 and Dec. 31, 2010, respectively. Also included are $27.2 million and $20.4 million of regulatory assets related to the non-qualified pension plan of which $12.1 million and $2.2 million is included in the current asset at Dec. 31, 2011 and Dec. 31, 2010, respectively.

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

(c) Includes the fair value of certain long-term PPAs used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.

(d) Includes amounts recorded for future recovery of AROs, less amounts recovered through nuclear decommissioning accruals and gains from decommissioning investments.

(e) Includes over- or under-recovered costs for DSM and conservation programs as well as incentives allowed in certain jurisdictions.

(f) As described in Note 12, in 2011 the CPUC determined that the customers' share of REC margins will be netted against the RESA regulatory asset balance. This is reflected in the Dec. 31, 2011 regulatory asset balance.

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16. Segments and Related Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Given the similarity of the regulated electric and regulated natural gas utility operations of its utility subsidiaries, Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits, and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $92.7 million and $97.6 million as of Dec. 31, 2011 and 2010, respectively, included in the regulated natural gas segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2011					
Operating revenues from external customers	$ 8,766,593	$ 1,811,926	$ 76,251	$ -	$ 10,654,770
Intersegment revenues	1,269	2,358	-	(3,627)	-
Total revenues	$ 8,767,862	$ 1,814,284	$ 76,251	$ (3,627)	$ 10,654,770
Depreciation and amortization	$ 773,392	$ 106,870	$ 10,357	$ -	$ 890,619
Interest charges and financing costs	402,668	52,115	108,134	-	562,917

Income tax expense (benefit)	473,848	57,408	(62,940)	-	468,316
Income (loss) from continuing operations	788,967	101,842	(49,435)	-	841,374

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2010					
Operating revenues from external customers	$8,451,845	$1,782,582	$76,520	$ -	$10,310,947
Intersegment revenues	1,015	5,653	-	(6,668)	-
Total revenues	$8,452,860	$1,788,235	$76,520	$(6,668)	$10,310,947
Depreciation and amortization	$748,815	$99,220	$10,847	$ -	$858,882
Interest charges and financing costs	380,074	49,314	119,233	-	548,621
Income tax expense (benefit)	434,756	59,790	(57,911)	-	436,635
Income (loss) from continuing operations	665,155	114,554	(27,753)	-	751,956

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
2009					
Operating revenues from external customers	$7,704,723	$1,865,703	$73,877	$ -	$9,644,303
Intersegment revenues	816	2,931	-	(3,747)	-
Total revenues	$7,705,539	$1,868,634	$73,877	$(3,747)	$9,644,303
Depreciation and amortization	$711,090	$95,633	$11,329	$ -	$818,052
Interest charges and financing costs	371,525	44,572	105,758	-	521,855
Income tax expense (benefit)	357,128	81,956	(67,770)	-	371,314
Income (loss) from continuing operations	611,851	108,948	(35,275)	-	685,524

17. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
(Amounts in thousands, except per share data)	March 31, 2011	June 30, 2011	Sept. 30, 2011	Dec. 31, 2011
Operating revenues	$2,816,540	$ 2,438,222	$ 2,831,598	$ 2,568,410
Operating income	426,663	359,442	651,496	344,001
Income from continuing operations	203,467	158,671	338,295	140,941
Discontinued operations — income (loss)	102	91	37	(432)
Net income	203,569	158,762	338,332	140,509
Earnings available to common shareholders	202,509	157,702	333,658	140,509
Earnings per share total — basic	$0.42	$ 0.33	$ 0.69	$ 0.29
Earnings per share total — diluted	0.42	0.33	0.69	0.29
Cash dividends declared per common share	0.25	0.26	0.26	0.26

	Quarter Ended			
(Amounts in thousands, except per share data)	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010
Operating revenues	$2,807,462	$ 2,307,764	$ 2,628,787	$ 2,566,934
Operating income	403,665	325,304	568,630	322,370
Income from continuing operations	167,340	135,625	312,488	136,503
Discontinued operations — income (loss)	(222)	4,151	(182)	131
Net income	167,118	139,776	312,306	136,634
Earnings available to common shareholders	166,058	138,716	311,246	135,573
Earnings per share total — basic	$0.36	$ 0.30	$ 0.68	$ 0.29
Earnings per share total — diluted	0.36	0.30	0.67	0.29

Cash dividends declared per common share	0.25	0.25	0.25	0.25

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18. Asset Acquisition and Sale

Acquisition of Generation Assets — In December 2010, PSCo purchased Blue Spruce Energy Center and Rocky Mountain Energy Center from Calpine Development Holdings, Inc. and Riverside Energy Center LLC for $739.0 million plus an additional $3.0 million for working capital adjustments. The working capital adjustments consisted of the settlement of PSCo's most recent purchases of energy and capacity under the terminated purchased power agreements, adjusted for accrued operating liabilities of the acquired plants of $6.5 million.

The Blue Spruce Energy Center is a 310 MW simple cycle natural gas-fired power plant that began commercial operations in 2003. The Rocky Mountain Energy Center is a 652 MW combined-cycle natural gas-fired power plant that began commercial operations in 2004. Both power plants previously provided energy and capacity to PSCo under purchased power agreements, which were set to expire in 2013 and 2014, respectively. The acquisition developed out of PSCo's resource planning activities, in which customers' future energy needs are addressed in a formal planning process for meeting PSCo's generation obligations, considering various assumptions and objectives including prices, reliability, and emissions levels. The generation assets were offered to PSCo as a competitive bid in the resource planning process, and the offer was the least cost option for thermal generation resources.

The purchase price has been allocated as follows based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition, including working capital adjustments of approximately $0.2 million recorded in 2011 which were identified through examination of the plants' books and records:

(Thousands of Dollars)		
Assets acquired		
Inventory	$	3,791
Property, plant and equipment		735,959
Total assets acquired		739,750
Liabilities assumed		
Accrued expenses		7,437
Total liabilities assumed		7,437
Net assets acquired	$	732,313

Operating results for the plants subsequent to the date of acquisition are included in the consolidated statements of income for the years ended Dec. 31, 2010 and Dec. 31, 2011.

Sale of Lubbock Electric Distribution Assets — In November 2009, SPS entered into an asset purchase agreement with the city of Lubbock, Texas. This agreement had set forth that SPS would sell its electric distribution system assets within the city limits to Lubbock Power and Light (LP&L) for approximately $87 million. The sale and related transactions eliminate the inefficiencies of maintaining duplicate distribution systems, by both SPS and by the city-owned LP&L.

SPS served about 24,000 customers within Lubbock, representing about 25 percent of the total customers in the dually certified service area. As part of this transaction, SPS will continue to provide wholesale power to meet the electric load for these customers, initially by amending the current wholesale full-requirements contract with WTMPA, which provides service to LP&L through 2019 and then for an additional 25 years under a new contract directly with LP&L when the WTMPA contract terminates. Both of these wholesale power agreements provide for formula rates that change annually based on the actual cost of service. The formula rate with WTMPA reflects an initial 10.5 percent ROE. All or portions of this transaction were reviewed and approved by the PUCT, the NMPRC and the FERC.

Additionally, SPS and the city of Lubbock entered into an amended long-term treated sewage effluent water agreement under which SPS will continue to purchase waste water from the city for cooling SPS' Jones Station southeast of Lubbock.

In October 2010, the transaction closed resulting in a pre-tax gain of approximately $20 million that has been deferred as a regulatory liability and will be shared with retail customers in Texas over a four year period.

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

None.

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Item 9A — Controls and Procedures

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Dec. 31, 2011, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Controls Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting. Xcel Energy maintains internal control over financial reporting to provide reasonable assurance regarding the reliability of the financial reporting. Xcel Energy has evaluated and documented its controls in process activities, general computer activities, and on an entity-wide level. During the year and in preparation for issuing its report for the year ended Dec. 31, 2011 on internal controls under section 404 of the Sarbanes-Oxley Act of 2002, Xcel Energy conducted testing and monitoring of its internal control over financial reporting. Based on the control evaluation, testing and remediation performed, Xcel Energy did not identify any material control weaknesses, as defined under the standards and rules issued by the Public Company Accounting Oversight Board and as approved by the SEC and as indicated in Management Report on Internal Controls herein.

Item 9B — Other Information

None.

PART III

Item 10 — Directors, Executive Officers and Corporate Governance

Information required under this Item with respect to Directors and Corporate Governance is set forth in Xcel Energy Inc.'s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference. Information with respect to Executive Officers is included in Item 1 to this report.

Item 11 — Executive Compensation

Information required under this Item is set forth in Xcel Energy Inc.'s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required under this Item is contained in Xcel Energy Inc.'s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

Item 13 — Certain Relationships and Related Transactions, and Director Independence

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

Item 14 — Principal Accountant Fees and Services

Information required under this Item is contained in Xcel Energy Inc.’s Proxy Statement for its 2012 Annual Meeting of Shareholders, which is incorporated by reference.

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PART IV

Item 15 — Exhibits, Financial Statement Schedules

1.	Consolidated Financial Statements:
	Management Report on Internal Controls Over Financial Reporting — For the year ended Dec. 31, 2011.
	Report of Independent Registered Public Accounting Firm — Financial Statements
	Report of Independent Registered Public Accounting Firm — Internal Controls Over Financial Reporting Consolidated Statements of Income — For the three years ended Dec. 31, 2011, 2010 and 2009.
	Consolidated Statements of Cash Flows — For the three years ended Dec. 31, 2011, 2010 and 2009.
	Consolidated Balance Sheets — As of Dec. 31, 2011 and 2010.
2.	Schedule I — Condensed Financial Information of Registrant.
	Schedule II — Valuation and Qualifying Accounts and Reserves for the years ended Dec. 31, 2011, 2010 and 2009.
3.	Exhibits

* Indicates incorporation by reference
\+ Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors
t Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

PSCo

2.01* t	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers, and PSCo, as Purchaser, dated as of April 2, 2010 (excluding certain schedules and exhibits referred to in the agreement, as amended, which the Registrant agrees to furnish supplemental to the SEC upon request) (Exhibit 2.01 to Form 10-Q for the quarter ended June 30, 2010 (file no. 001-03034)).

Xcel Energy Inc.

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 20, 2011 (Exhibit 3.01 to Form 8-K of Xcel Energy file number 001-03034, dated May 18, 2011).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).

Xcel Energy Inc.

4.01*	Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, National Association (NA), as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Dec. 18, 2000).
4.02*	Supplemental Indenture No. 3 dated June 1, 2006 between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, NA, as Trustee, creating $300 million principal amount of 6.5 percent Senior

	Notes, Series due 2036 (Exhibit 4.01 to Current Report on Form 8-K (file no. 001-03034) dated June 6, 2006).
4.03*	Supplemental Indenture No. 4 dated March 30, 2007 between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, NA, as Trustee, creating $253.979 million aggregate principal amount of 5.613 percent Senior Notes, Series due 2017 (Exhibit 4.1 to Form 8-K (file no. 001-03034) dated March 30, 2007).
4.04*	Junior Subordinated Indenture, dated as of Jan. 1, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, NA, as Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.05*	Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between Xcel Energy Inc. and Wells Fargo Bank, Minnesota, NA, as Trustee, creating $400 million principal amount of 7.6 percent Junior Subordinated Notes, Series due 2068 (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.06*	Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.07*	Supplemental Indenture No. 5 dated as of May 1, 2010 between Xcel Energy Inc. and Wells Fargo Bank, NA, as Trustee, creating $550 million principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 13, 2010).
4.08*	Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association (NA), as Trustee, creating $250 million principal amount of 4.80 percent Senior Notes, Series due 2041. (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).

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NSP-Minnesota

4.09*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP-Minnesota to Harris Trust and Savings Bank, as Trustee, providing for the issuance of First Mortgage Bonds (Exhibit 4.02 to Form 10-K of NSP-Minnesota for the year 1988, file no. 001-03034). Supplemental Indentures between NSP-Minnesota and said Trustee, dated as follows:
	Supplemental Indenture dated June 1, 1995, creating $250 million principal amount of 7.125 percent First Mortgage Bonds, Series due July 1, 2025 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated June 28, 1995, Rider A).
	Supplemental Indenture dated April 1, 1997, creating $100 million principal amount of 8.5 percent First Mortgage Bonds, Series due Sept. 1, 2019 and $27.9 million principal amount of 8.5 percent First Mortgage Bonds, Series due March 1, 2019 (Exhibit 4.47 to Form 10-K (file no. 001-03034) dated Dec. 31, 1997.)
	Supplemental Indenture dated March 1, 1998, creating $150 million principal amount of 6.5 percent First Mortgage Bonds, Series due March 1, 2028 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated March 11, 1998, Rider A).
4.10*	Supplemental Indenture Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.11*	Indenture, dated July 1, 1999, between NSP-Minnesota and Norwest Bank Minnesota, NA, as Trustee, providing for the issuance of Sr. Debt Securities. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-03034) dated July 21, 1999).
4.12*	Supplemental Indenture, dated Aug. 18, 2000, supplemental to the Indenture dated July 1, 1999, among Xcel Energy, NSP-Minnesota and Wells Fargo Bank Minnesota, NA, as Trustee (Assignment and Assumption of Indenture). (Exhibit 4.63 to NSP-Minnesota Form 10-12G (file no. 000-31709) dated Oct. 5, 2000).
4.13*	Supplemental Indenture dated July 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $69 million principal amount of 8.5 percent First Mortgage Bonds, Series due April 1, 2030 (Exhibit 4.06 to NSP-Minnesota Current Report on Form 10-Q, (file no. 000-31387) dated Sept. 30, 2002).
4.14*	Supplemental Trust Indenture dated Aug. 1, 2002 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $450 million principal amount of 8.0 percent First Mortgage Bonds, Series due Aug. 28, 2012 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 000-31387) dated Aug. 22, 2002).
4.15*	Supplemental Indenture dated July 1, 2005 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $250 million principal amount of 5.25 percent First Mortgage Bonds, Series due July 15, 2035 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 000-31387) dated July 14, 2005).

4.16*	Supplemental Indenture dated May 1, 2006 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee, creating $400 million principal amount of 6.25 percent First Mortgage Bonds, Series due June 1, 2036 (Exhibit 4.01 to NSP-Minnesota Current Report on Form 8-K, (file no. 000-31387) dated May 18, 2006).
4.17*	Supplemental Indenture, dated June 1, 2007, between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
4.18*	Supplemental Indenture dated March 1, 2008 between NSP-Minnesota and BNY Midwest Trust Company, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated March 11, 2008).
4.19*	Supplemental Indenture dated as of Nov. 1, 2009 between NSP-Minnesota and The Bank of New York Mellon Trust Co., NA, as successor Trustee, creating $300 million principal amount of 5.35 percent First Mortgage Bonds, Series due Sept. 1, 2039 (Exhibit 4.01 of Form 8-K of NSP-Minnesota dated Nov. 16, 2009 (file no. 001-31387)).
4.20*	Supplemental Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of 1.950 percent First Mortgage Bonds, Series due Aug. 15, 2015 and $250 million principal amount of 4.850 percent First Mortgage Bonds, Series due Aug. 15, 2040 (Exhibit 4.01 to Form 8-K dated Aug. 11, 2010 (file no. 001-31387)).

NSP-Wisconsin

4.21*	Supplemental and Restated Trust Indenture, dated March 1, 1991, between NSP-Wisconsin and First Wisconsin Trust company, providing for the issuance of First Mortgage Bonds (Exhibit 4.01 to Registration Statement 33-39831).
4.22*	Supplemental Trust Indenture, dated April 1, 1991 (Exhibit 4.01 to Form 10-Q (file no. 001-03140) for the quarter ended March 31, 1991).
4.23*	Supplemental Trust Indenture, dated Dec. 1, 1996. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Dec. 12, 1996).

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4.24*	Trust Indenture dated Sept. 1, 2000, between NSP-Wisconsin and Firstar Bank, NA as Trustee. (Exhibit 4.01 to Form 8-K (file no. 001-03140) dated Sept. 25, 2000).
4.25*	Supplemental Trust Indenture dated Sept. 1, 2003 between NSP-Wisconsin and US Bank NA, supplementing indentures dated April 1, 1947 and March 1, 1991 (Exhibit 4.05 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.26*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between NSP-Wisconsin and U.S. Bank NA, as successor Trustee, creating $200 million principal amount of 6.375 percent First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of NSP-Wisconsin dated Sept. 3, 2008 (file no. 001-03140)).

PSCo

4.27*	Indenture, dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 — Exhibit 4(a)).
4.28*	Indentures supplemental to Indenture dated as of Oct. 1, 1993, between PSCo and Morgan Guaranty Trust Company of New York, as trustee,:

Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.	Dated as of	Previous Filing: Form; Date or file no.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)	Aug. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.03
Jan. 1, 1994	10-K, 1993	4(b)(3)	Sept. 1, 2002	8-K, Sept. 18, 2002 (001-03280)	4.01
Sept. 2, 1994	8-K, September 1994	4(b)	Sept. 15, 2002	10-Q, Sept. 30, 2002 (001-03280)	4.04
May 1, 1996	10-Q, June 30, 1996	4(b)	March 1, 2003	S-3, April 14, 2003 (333-104504)	4(b)(3)
Nov. 1, 1996	10-K, 1996 (001-03280)	4(b)(3)	April 1, 2003	10-Q May 15, 2003 (001-03280)	4.02
Feb. 1, 1997	10-Q, March 31, 1997 (001-03280)	4(a)	May 1, 2003	S-4, June 11, 2003 (333-106011)	4.9
April 1, 1998	10-Q, March 31,1998 (001-03280)	4(b)	Sept. 1, 2003	8-K, Sept. 2, 2003 (001-03280)	4.02
			Sept. 15, 2003	Xcel 10-K, March 15, 2004 (001-03034)	4.100
			Aug. 1, 2005	PSCo 8-K, Aug. 18, 2005 (001-03280)	4.02

4.29*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities and Supplemental Indenture dated July 15, 1999, between PSCo and The Bank of New York (Exhibits 4.1 and 4.2 to Form 8-K (file no. 001-03280) dated July 13, 1999).
4.30*	Financing Agreement between Adams County, Colorado and PSCo, dated as of Aug. 1, 2005 relating to $129.5 million Adams County, Colorado Pollution Control Refunding Revenue Bonds, 2005 Series A. (Exhibit 4.01 to PSCo Current Report on Form 8-K, dated Aug. 18, 2005, file number 001-3280).
4.31*	Supplemental Indenture, dated Aug. 1, 2007, between PSCo and U.S. Bank Trust NA, as successor Trustee (Exhibit 4.01 to PSCo Form 8-K (file no 001-03280) dated Aug. 14, 2007).
4.32*	Supplemental Indenture dated as of Aug. 1, 2008, between PSCo and U.S. Bank Trust NA, as successor Trustee, creating $300 million principal amount of 5.80 percent First Mortgage Bonds,

	Series No. 18 due 2018 and $300 million principal amount of 6.50 percent First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of PSCo dated Aug. 6, 2008 (file no. 001-03280)).
4.33*	Supplemental Indenture dated as of May 1, 2009 between PSCo and U.S. Bank Trust NA, as successor Trustee, creating $400 million principal amount of 5.125 percent First Mortgage Bonds, Series No. 20 due 2019 (Exhibit 4.01 of Form 8-K of PSCo dated May 28, 2009 (file no. 001-03280)).
4.34*	Supplemental Indenture dated as of Nov. 1, 2010 between PSCo and U.S. Bank Trust NA, as successor Trustee, creating $400 million principal amount of 3.200 percent First Mortgage Bonds, Series No. 21 due 2020 (Exhibit 4.01 of Form 8-K of PSCo dated Nov. 16, 2010 (file no. 001-03280)).
4.35*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank NA, as successor Trustee, creating $250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041. (Exhibit 4.01 to Form 8-K dated Aug. 9, 2011 (file no. 001-03280)).

SPS

4.36*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.2 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).
4.37*	First Supplemental Indenture dated March 1, 1999 between SPS and The Chase Manhattan Bank (Exhibit 99.3 to Form 8-K (file no. 001-03789) dated Feb. 25, 1999).

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4.38*	Second Supplemental Indenture dated Oct. 1, 2001 between SPS and The Chase Manhattan Bank (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 23, 2001).
4.39*	Third Supplemental Indenture dated Oct. 1, 2003 to the indenture dated Feb. 1, 1999 between SPS and JPMorgan Chase Bank, as successor Trustee, creating $100 million principal amount of Series C and Series D Notes, 6 percent due 2033 (Exhibit 4.04 to Xcel Energy Form 10-Q (file no. 001-03034) dated Nov. 13, 2003).
4.40*	Fourth Supplemental Indenture dated Oct. 1, 2006 between SPS and The Bank of New York, as successor Trustee (Exhibit 4.01 to Form 8-K (file no. 001-03789) dated Oct. 3, 2006).
4.41*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 — Exhibit 4(b)).
4.42*	Supplemental Trust Indenture dated as of Nov. 1, 2008 between SPS and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250 million principal amount of Series G Senior Notes, 8.75 percent due 2018 (Exhibit 4.01 of Form 8-K of SPS, dated Nov. 14, 2008 (file no. 001- 03789)).
4.43*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank NA, as Trustee. (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
4.44*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank NA, as Trustee, creating $200 million principal amount of 4.50 percent First Mortgage Bonds, Series No. 1 due 2041. (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).

Xcel Energy Inc.

10.01*+	Xcel Energy Non-Qualified Pension Plan (2009 Restatement) (Exhibit 10.02 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.02*+	Xcel Energy Senior Executive Severance Policy (2009 Amendment and Restatement) (Exhibit 10.05 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.03*+	Xcel Energy Non-employee Directors' Deferred Compensation Plan as amended and restated Jan. 1, 2009 (Exhibit 10.08 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.04*	Form of Services Agreement between Xcel Energy Services Inc. and utility companies (Exhibit H-1 to Form U5B (file no. 001-03034) dated Nov. 16, 2000).
10.05*+	Xcel Energy Supplemental Executive Retirement Plan as amended and restated Jan. 1, 2009 (Exhibit 10.17 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2008).
10.06*+	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.06 to Form 10-Q of Xcel Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.07*+	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement (Exhibit 10.08 to Form 10-Q of Xcel

	Energy (file no. 001-03034) for the quarter ended Sept. 30, 2009).
10.08*	Xcel Energy Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.09*+	Xcel Energy 2010 Executive Annual Discretionary Award Plan (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2009).
10.10*+	Xcel Energy 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.11*+	Xcel Energy 2010 Executive Annual Discretionary Award Plan (as amended and restated effective Dec. 15, 2010) (Exhibit 10.23 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.12*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Bonus Stock Agreement (Exhibit 10.24 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.13*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Performance Share Agreement (Exhibit 10.25 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.14*+	Xcel Energy 2005 Long-Term Incentive Plan Form of Restricted Stock Unit Agreement (Exhibit 10.26 to Form 10-K of Xcel Energy (file no. 001-03034) for the year ended Dec. 31, 2010).
10.15*	Credit Agreement, dated as of March 17, 2011 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Capital, the investment banking division of Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.01 to Form 8-K of Xcel Energy, file number 001-03034, dated March 23, 2011).

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10.16*+	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy as amended and restated effective Feb. 23, 2011 (Appendix A to the Xcel Energy Definitive Proxy Statement (file no. 001-03034) filed April 5, 2011).
10.17+	Xcel Energy Inc. Nonqualified Deferred Compensation Plan (2009 Restatement) (as amended and restated effective Nov. 29, 2011).
10.18+	Second Amendment dated Oct. 26, 2011 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy.

NSP-Minnesota

10.19*	Ownership and Operating Agreement, dated March 11, 1982, between NSP-Minnesota, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3 (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, file no. 001-03034).
10.20*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to NSP-Wisconsin Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.21*	Credit Agreement, dated as of March 17, 2011 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Capital, the investment banking division of Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.02 to Form 8-K of Xcel Energy, file number 001-03034, dated March 23, 2011).

NSP-Wisconsin

10.22*	Restated Interchange Agreement dated Jan. 16, 2001 between NSP-Wisconsin and NSP-Minnesota (Exhibit 10.01 to Form S-4 (file no. 333-112033) dated Jan. 21, 2004).
10.23*	Credit Agreement, dated as of March 17, 2011 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Capital, the investment banking division of Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.03 to Form 8-K of Xcel Energy, file number 001-03034, dated March 23, 2011).

PSCo

10.24*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1984 — Exhibit 10I (1)).
10.25*	

	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Co. (Form 10-K (file no. 001-03280) Dec. 31, 1988 — Exhibit 10I (2)).
10.26*	Proposed Settlement Agreement excerpts, as filed with the CPUC (Exhibit 99.02 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.27*	Settlement Agreement among PSCo and Concerned Environmental and Community Parties, dated Dec. 3, 2004 (Exhibit 99.03 to Form 8-K (file no. 001-03034) dated Dec. 3, 2004).
10.28*	Credit Agreement, dated as of March 17, 2011 among PSCo as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Capital, the investment banking division of Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.04 to Form 8-K of Xcel Energy, file number 001-03034, dated March 23, 2011).
SPS	
10.29*	Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (file no. 001-03789), May 14, 1979 — Exhibit 3).
10.30*	Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO, dated July 1, 1978 (Form 8-K, (file no. 001-03789) May 14, 1979 — Exhibit 5(A)).
10.31*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Co. and TUCO (Form 8-K, (file no. 3789) May 14, 1979 — Exhibit 5(B)).
10.32*	Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10(b)).
10.33*	Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (file no. 3789) Feb. 28, 1982 — Exhibit 10I).
10.34*	Power Purchase Agreement dated May 23, 1997 between Borger Energy Associates, L.P, and SPS.
10.35*	Credit Agreement, dated as of March 17, 2011 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Capital, the investment banking division of Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Exhibit 99.05 to Form 8-K of Xcel Energy, file number 001-03034, dated March 23, 2011).

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Xcel Energy Inc.

12.01	Statement of Computation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of Xcel Energy Inc.
23.01	Consent of Independent Registered Public Accounting Firm.
24.01	Written Consent Resolution of the Board of Directors of Xcel Energy Inc., adopting Power of Attorney.
31.01	Principal Executive Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certification pursuant to 18 U.S. C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Cash Flows, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Common Stockholders' Equity and Comprehensive Income, (v) Consolidated Statements of Capitalization, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SCHEDULE I

XCEL ENERGY INC.
CONDENSED STATEMENTS OF INCOME
(amounts in thousands, except per share data)

	Year Ended Dec. 31		
	2011	2010	2009
Income			
Equity earnings of subsidiaries	$904,315	$818,212	$743,798
Total income	904,315	818,212	743,798
Expenses and other deductions			
Operating expenses	14,513	11,849	9,116
Other income	(760)	(681)	(1,295)
Interest charges and financing costs	104,297	112,510	101,118
Total expenses and other deductions	118,050	123,678	108,939
Income from continuing operations before income taxes	786,265	694,534	634,859
Income tax benefit	(55,109)	(57,422)	(50,665)
Income from continuing operations	841,374	751,956	685,524
Income (loss) from discontinued operations, net of tax	(202)	3,878	(4,637)
Net income	841,172	755,834	680,887
Dividend requirements on preferred stock	3,534	4,241	4,241
Premium on redemption of preferred stock	3,260	-	-
Earnings available to common shareholders	$834,378	$751,593	$676,646
Weighted average common shares outstanding:			
Basic	485,039	462,052	456,433
Diluted	485,615	463,391	457,139
Earnings per average common share — basic:			
Income from continuing operations	$1.72	$1.62	$1.49
Income (loss) from discontinued operations	-	0.01	(0.01)
Earnings per share	$1.72	$1.63	$1.48
Earnings per average common share — diluted:			
Income from continuing operations	$1.72	$1.61	$1.49
Income (loss) from discontinued operations	-	0.01	(0.01)
Earnings per share	$1.72	$1.62	$1.48
Cash dividends declared per common share	$1.03	$1.00	$0.97

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XCEL ENERGY INC.
CONDENSED STATEMENTS OF CASH FLOWS
(amounts in thousands)

	Year Ended Dec. 31		
	2011	2010	2009
Operating activities			
Net cash provided by operating activities	$595,732	$537,840	$627,013
Investing activities			
Capital contributions to subsidiaries	(287,495)	(523,369)	(297,004)
Net cash used in investing activities	(287,495)	(523,369)	(297,004)
Financing activities			
Proceeds from (repayment of) short-term borrowings, net	(21,000)	(216,000)	13,750
Proceeds from issuance of long-term debt	246,877	543,923	-
Repayment of long-term debt	-	(358,636)	-
Proceeds from issuance of common stock	38,691	457,258	20,133
Redemption of preferred stock	(104,980)	-	-
Dividends paid	(474,760)	(432,110)	(414,922)
Net cash used in financing activities	(315,172)	(5,565)	(381,039)
Net change in cash and cash equivalents	(6,935)	8,906	(51,030)
Cash and cash equivalents at beginning of period	9,654	748	51,778
Cash and cash equivalents at end of period	$2,719	$9,654	$748

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XCEL ENERGY INC.
CONDENSED BALANCE SHEETS
(amounts in thousands)

	Dec. 31	
	2011	2010
Assets		
Cash and cash equivalents	$2,719	$9,654
Accounts receivable from subsidiaries	271,895	266,323
Other current assets	28,399	35,276
Total current assets	303,013	311,253
Investment in subsidiaries	10,089,116	9,559,780
Other assets	154,353	134,157
Total other assets	10,243,469	9,693,937
Total assets	$10,546,482	$10,005,190
Liabilities and Equity		
Dividends payable	$126,487	$122,847
Short-term debt	127,000	148,000
Other current liabilities	36,000	24,453
Total current liabilities	289,487	295,300
Other liabilities	31,616	29,192
Total other liabilities	31,616	29,192
Commitments and contingencies		
Capitalization		
Long-term debt	1,743,181	1,492,199
Preferred stockholders' equity	-	104,980
Common stockholders' equity	8,482,198	8,083,519
Total capitalization	10,225,379	9,680,698
Total liabilities and equity	$10,546,482	$10,005,190

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NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Xcel Energy's consolidated statements of common stockholders' equity and OCI in Part II, Item 8.

Basis of Presentation — The condensed financial information of Xcel Energy Inc. is presented to comply with Rule 12-04 of Regulation S-X. Xcel Energy Inc.'s investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded in the balance sheets. The income from operations of the subsidiaries is reported on a net basis as equity in income of subsidiaries.

Related Party Transactions — Xcel Energy Inc. presents its related party receivables net of payables. Accounts receivable and payable with affiliates at Dec. 31 were:

	2011		2010	
(Thousands of Dollars)	Accounts Receivable	Accounts Payable	Accounts Receivable	Accounts Payable
NSP-Minnesota	$58,321	$-	$81,447	$-
NSP-Wisconsin	8,620	-	12,510	-
PSCo	83,263	-	66,828	(11,532)
SPS	17,440	-	24,769	-
Xcel Energy Services Inc.	52,994	(1,690)	35,311	(997)
Xcel Energy Ventures Inc.	37,700	-	41,692	-
Other subsidiaries of Xcel Energy Inc.	20,574	(5,327)	20,076	(3,784)
	$278,912	$(7,017)	$282,633	$(16,313)

Dividends — Cash dividends paid to Xcel Energy Inc. by its subsidiaries were $626 million, $663 million, and $647 million for the years ended Dec. 31, 2011, 2010 and 2009, respectively.

See Xcel Energy's notes to the consolidated financial statements in Part II, Item 8 for other disclosures.

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SCHEDULE II

XCEL ENERGY INC. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DEC. 31, 2011, 2010 AND 2009
(amounts in thousands)

		Additions			
	Balance at Jan. 1	Charged to Costs and Expenses	Charged to Other Accounts (a)	Deductions from Reserves (b) (c)	Balance at Dec. 31
Allowance for bad debts:					
2011	$54,563	$44,521	$ 15,636	$ 56,155	$58,565
2010	56,103	44,068	15,202	60,810	54,563
2009	64,239	49,023	21,869	79,028	56,103
NOL and tax credit valuation allowances:					
2011	$1,927	$4,379	$ -	$ 623	$5,683
2010	9,324	240	-	7,637	1,927
2009	2,044	7,280	-	-	9,324

(a)Recovery of amounts previously written off as related to allowance for bad debts.
(b)Principally bad debts written off or transferred as related to allowance for bad debts.
(c)Reductions to valuation allowances for NOL and tax credit carryforwards primarily due to changes in tax laws and expirations of certain carryforwards.

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SIGNATURES

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

XCEL ENERGY INC.

Feb. 24, 2012

By: /s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

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

/s/ BENJAMIN G.S. FOWKE III Benjamin G.S. Fowke III	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ TERESA S. MADDEN Teresa S. Madden	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JEFFREY S. SAVAGE Jeffrey S. Savage	Vice President and Controller (Principal Accounting Officer)
* Fredric W. Corrigan	Director
* Richard K. Davis	Director
* Albert F. Moreno	Director
* Christopher J. Policinski	Director
* A. Patricia Sampson	Director
* James J. Sheppard	Director
* David A. Westerlund	Director
* Kim Williams	Director
*	Director

Timothy V. Wolf

*	/s/ TERESA S. MADDEN Teresa S. Madden	Attorney-in-Fact

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