XCEL ENERGY INC
Form 10-Q
April 27, 2012

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2012
or

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

Commission File Number: 1-3034

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota	41-0448030
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall Minneapolis, Minnesota	55401
(Address of principal executive offices)	(Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

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. xYes oNo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 oNo

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
oYes xNo

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at April 19, 2012
Common Stock, $2.50 par value	486,943,183 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

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

	Three Months Ended March 31	
	2012	2011
Operating revenues		
Electric	$1,936,782	$2,029,972
Natural gas	621,035	765,349
Other	20,262	21,219
Total operating revenues	2,578,079	2,816,540
Operating expenses		
Electric fuel and purchased power	863,980	931,828
Cost of natural gas sold and transported	417,946	543,376
Cost of sales — other	7,304	8,055
Operating and maintenance expenses	510,684	510,027
Conservation and demand side management program expenses	63,707	75,298
Depreciation and amortization	228,672	224,723
Taxes (other than income taxes)	105,624	96,570
Total operating expenses	2,197,917	2,389,877
Operating income	380,162	426,663
Other income, net	3,737	4,766
Equity earnings of unconsolidated subsidiaries	7,158	7,713
Allowance for funds used during construction — equity	13,450	13,244
Interest charges and financing costs		
Interest charges — includes other financing costs of $6,080 and $5,260, respectively	151,830	144,354
Allowance for funds used during construction — debt	(6,607)	(7,436)
Total interest charges and financing costs	145,223	136,918
Income from continuing operations before income taxes	259,284	315,468
Income taxes	75,515	112,001
Income from continuing operations	183,769	203,467
Income from discontinued operations, net of tax	124	102
Net income	183,893	203,569
Dividend requirements on preferred stock	-	1,060
Earnings available to common shareholders	$183,893	$202,509
Weighted average common shares outstanding:		
Basic	487,360	483,641
Diluted	487,995	484,301

Earnings per average common share:		
Basic	$0.38	$0.42
Diluted	0.38	0.42
Cash dividends declared per common share	$0.26	$0.25

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended March 31	
	2012	2011
Net income	$183,893	$203,569
Other comprehensive income		
Pension and retiree medical benefits:		
Amortization of losses included in net periodic benefit cost, net of tax of $622 and $551, respectively	895	794
Derivative instruments:		
Net fair value increase, net of tax of $16,491 and $145, respectively	25,392	244
Reclassification of losses to net income, net of tax of $156 and $147, respectively	181	158
	25,573	402
Marketable securities:		
Net fair value increase, net of tax of $36 and $34, respectively	52	50
Other comprehensive income	26,520	1,246
Comprehensive income	$210,413	$204,815

See Notes to Consolidated Financial Statements

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

	Three Months Ended March 31	
	2012	2011
Operating activities		
Net income	$183,893	$203,569
Remove income from discontinued operations	(124)	(102)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	233,097	229,217
Conservation and demand side management program amortization	1,882	3,024
Nuclear fuel amortization	26,000	25,551
Deferred income taxes	167,426	114,852
Amortization of investment tax credits	(1,552)	(1,580)
Allowance for equity funds used during construction	(13,450)	(13,244)
Equity earnings of unconsolidated subsidiaries	(7,158)	(7,713)
Dividends from unconsolidated subsidiaries	8,028	8,454
Share-based compensation expense	3,883	9,895
Net derivative losses	7,133	14,495
Changes in operating assets and liabilities:		
Accounts receivable	(52,643)	(46,947)
Accrued unbilled revenues	197,330	157,996
Inventories	143,873	118,595
Other current assets	(71,547)	43,551
Accounts payable	(202,649)	(72,424)
Net regulatory assets and liabilities	61,872	17,853
Other current liabilities	17,711	5,491
Pension and other employee benefit obligations	(180,030)	(134,004)
Change in other noncurrent assets	(38,806)	10,520
Change in other noncurrent liabilities	(6,686)	(27,606)
Net cash provided by operating activities	477,483	659,443
Investing activities		
Utility capital/construction expenditures	(497,218)	(540,339)
Allowance for equity funds used during construction	13,450	13,244
Merricourt deposit	-	(90,833)
Purchase of investments in external decommissioning fund	(213,618)	(699,156)
Proceeds from the sale of investments in external decommissioning fund	213,618	699,156
Investment in WYCO Development LLC	(172)	(901)
Change in restricted cash	86,232	26
Other, net	(1,304)	(5,545)
Net cash used in investing activities	(399,012)	(624,348)
Financing activities		
Proceeds from short-term borrowings, net	120,000	65,100
Proceeds from issuance of long-term debt	745	-
Repayments of long-term debt, including reacquisition premiums	(758)	(551)

Proceeds from issuance of common stock	1,598	1,878
Repurchase of common stock	(18,529)	-
Purchase of common stock for settlement of equity awards	(23,307)	-
Dividends paid	(119,162)	(115,621)
Net cash used in financing activities	(39,413)	(49,194)
Net change in cash and cash equivalents	39,058	(14,099)
Cash and cash equivalents at beginning of period	60,684	108,437
Cash and cash equivalents at end of period	$99,742	$94,338
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(156,275)	$(150,473)
Cash (paid) received for income taxes, net	(1,173)	59,051
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$224,316	$116,145
Issuance of common stock for reinvested dividends and 401(k) plans	18,815	20,419

See Notes to Consolidated Financial Statements

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

	March 31, 2012	Dec. 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$99,742	$ 60,684
Restricted cash	9,055	95,287
Accounts receivable, net	718,145	753,120
Accrued unbilled revenues	491,410	688,740
Inventories	474,359	618,232
Regulatory assets	333,053	402,235
Derivative instruments	61,971	64,340
Deferred income taxes	162,353	178,446
Prepayments and other	192,746	121,480
Total current assets	2,542,834	2,982,564
Property, plant and equipment, net	22,672,686	22,353,367
Other assets		
Nuclear decommissioning fund and other investments	1,537,490	1,463,515
Regulatory assets	2,361,648	2,389,008
Derivative instruments	146,438	152,887
Other	192,157	155,926
Total other assets	4,237,733	4,161,336
Total assets	$29,453,253	$ 29,497,267
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$1,309,681	$ 1,059,922
Short-term debt	339,000	219,000
Accounts payable	786,187	902,078
Regulatory liabilities	220,526	275,095
Taxes accrued	359,064	289,713
Accrued interest	161,930	177,111
Dividends payable	126,601	126,487
Derivative instruments	56,132	157,414
Other	348,921	381,819
Total current liabilities	3,708,042	3,588,639
Deferred credits and other liabilities		
Deferred income taxes	4,212,924	4,020,377
Deferred investment tax credits	85,819	86,743
Regulatory liabilities	1,107,818	1,101,534
Asset retirement obligations	1,662,175	1,651,793
Derivative instruments	260,152	263,906
Customer advances	247,224	248,345

Pension and employee benefit obligations	813,792	1,001,906
Other	219,273	203,313
Total deferred credits and other liabilities	8,609,177	8,577,917
Commitments and contingencies		
Capitalization		
Long-term debt	8,598,363	8,848,513
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 486,935,997 and 486,493,933 shares outstanding at March 31, 2012 and Dec. 31, 2011, respectively	1,217,339	1,216,234
Additional paid in capital	5,298,572	5,327,443
Retained earnings	2,089,275	2,032,556
Accumulated other comprehensive loss	(67,515)	(94,035)
Total common stockholders' equity	8,537,671	8,482,198
Total liabilities and equity	$29,453,253	$ 29,497,267

See Notes to Consolidated Financial Statements

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended March 31, 2012 and 2011						
Balance at Dec. 31, 2010	482,334	$1,205,834	$5,229,075	$1,701,703	$ (53,093)	$ 8,083,519
Comprehensive income:						
Net income				203,569		203,569
Other comprehensive income					1,246	1,246
Comprehensive income						204,815
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(122,826)		(122,826)
Issuances of common stock	1,831	4,577	1,652			6,229
Share-based compensation			10,806			10,806
Balance at March 31, 2011	484,165	$1,210,411	$5,241,533	$1,781,386	$ (51,847)	$ 8,181,483
Balance at Dec. 31, 2011	486,494	$1,216,234	$5,327,443	$2,032,556	$ (94,035)	$ 8,482,198
Comprehensive income:						
Net income				183,893		183,893
Other comprehensive income					26,520	26,520
Comprehensive income						210,413
Dividends declared:						
Common stock				(127,174)		(127,174)
Issuances of common stock	1,142	2,855	2,288			5,143
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity awards			(23,307)			(23,307)
Share-based compensation			8,927			8,927
Balance at March 31, 2012	486,936	$1,217,339	$5,298,572	$2,089,275	$ (67,515)	$ 8,537,671

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of March 31, 2012 and Dec. 31, 2011 and the results of its operations, cash flows and changes in stockholders' equity for the three months ended March 31, 2012 and 2011. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after March 31, 2012 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2011 balance sheet information has been derived from the audited 2011 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, filed with the SEC on Feb. 24, 2012. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Fair Value Measurement — In May 2011, the Financial Accounting Standards Board (FASB) issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (Accounting Standards Update (ASU) No. 2011-04), which provides 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 requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the accounting and disclosure guidance effective Jan. 1, 2012, and the implementation did not have a material impact on its consolidated financial statements. For required fair value measurement disclosures, see Note 8.

Comprehensive Income — In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05), which requires the presentation of the components of net income, the components of other comprehensive income (OCI) and total comprehensive income in either a single continuous financial statement of comprehensive income or in two separate, but consecutive financial 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 requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the financial statement presentation guidance effective Jan. 1, 2012.

Recently Issued

Balance Sheet Offsetting — In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which requires 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 disclosure requirements 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.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	March 31, 2012	Dec. 31, 2011
Accounts receivable, net		
Accounts receivable	$776,140	$811,685
Less allowance for bad debts	(57,995)	(58,565)
	$718,145	$753,120
Inventories		
Materials and supplies	$207,729	$202,699
Fuel	176,874	236,023
Natural gas	89,756	179,510
	$474,359	$618,232
Property, plant and equipment, net		
Electric plant	$27,393,092	$27,254,541
Natural gas plant	3,700,424	3,676,754
Common and other property	1,484,878	1,546,643
Plant to be retired (a)	115,401	151,184
Construction work in progress	1,315,390	1,085,245
Total property, plant and equipment	34,009,185	33,714,367
Less accumulated depreciation	(11,731,341)	(11,658,351)
Nuclear fuel	2,062,790	1,939,299
Less accumulated amortization	(1,667,948)	(1,641,948)
	$22,672,686	$22,353,367

(a) In 2010, in response to the Clean Air Clean Jobs Act (CACJA), the Colorado Public Utilities Commission (CPUC) approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. In 2011, Cherokee Unit 2 was taken out of service. Amounts are presented net of accumulated depreciation.

4. Income Taxes

Except to the extent noted below, the circumstances set forth in Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

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.

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 March 31, 2012, 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 March 31, 2012, there were no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (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.

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

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
Unrecognized tax benefit — Permanent tax positions	$4.4	$4.3
Unrecognized tax benefit — Temporary tax positions	29.5	30.4
Unrecognized tax benefit balance	$33.9	$34.7

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
NOL and tax credit carryforwards	$(32.8)	$(33.6)

The decrease in the unrecognized tax benefit balance of $0.8 million from Dec. 31, 2011 to March 31, 2012 was due to adjustments for prior years' activity. Xcel Energy's amount of unrecognized tax benefits could change in the next 12 months as the Internal Revenue Service 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.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at March 31, 2012 and Dec. 31, 2011 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of March 31, 2012 or Dec. 31, 2011.

Federal Tax Loss Carryback Claims — Xcel Energy completed an analysis in the first quarter of 2012 on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a discrete tax benefit of approximately $15 million.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending and Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

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, a requested return on equity (ROE) of 11.25 percent, an electric rate base of $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 August 2011, NSP-Minnesota submitted supplemental testimony, revising its requested rate increase to approximately $122 million for 2011 and an additional increase of approximately $29 million in 2012.

In November 2011, NSP-Minnesota reached a settlement agreement with various parties, which resolved all financial issues and several rate design issues. The settlement agreement includes:

- A rate increase of approximately $58 million in 2011 and an incremental rate increase of $14.8 million in 2012 based on an ROE of 10.37 percent and an equity ratio of 52.56 percent.
- A reduction to depreciation expense and NSP-Minnesota's rate request by $30 million.
- The ability for NSP-Minnesota to seek deferred accounting for incremental property tax increases associated with electric and natural gas businesses in 2012.
- The stipulation that NSP-Minnesota will not file an electric rate case prior to Nov. 1, 2012, provided that both the settlement agreement and the property tax filing are approved by the MPUC.

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In February 2012, NSP-Minnesota filed to reduce the interim rate request to $72.8 million to align with the settlement agreement. On March 29, 2012, the MPUC approved the settlement and a written order is pending. As of March 31, 2012 and Dec. 31, 2011, NSP-Minnesota recorded a provision for revenue subject to refund of approximately $78 million and $67 million, respectively, to align with the settlement agreement.

NSP-Minnesota – Minnesota Property Tax Deferral Request — As part of the settlement agreement in the Minnesota electric rate case, the settling parties acknowledged that NSP-Minnesota would be filing a petition seeking deferred accounting for 2012 property tax expense in excess of the level approved in the rate case. The settling parties waived any right to object to the petition, but reserved the right to review and comment on the petition. In December 2011, NSP-Minnesota filed the petition to request deferral of approximately $28 million of incremental 2012 property taxes that will not be recovered in base rates. The estimate of 2012 incremental property taxes has been subsequently revised to approximately $24 million.

In April 2012, the Minnesota Department of Commerce (DOC) filed comments on the petition. The DOC concluded that NSP-Minnesota had not made a reasonable case for deferred accounting and recommended that the MPUC deny NSP-Minnesota's request to defer incremental 2012 property taxes and also opposed the proposed rider mechanism. The Xcel Large Industrials and the Minnesota Chamber of Commerce filed comments in support of the deferred accounting treatment as preferable to a rider mechanism, with the understanding that all costs will be reviewed in NSP-Minnesota's next rate case. Until the MPUC rules on the issue, NSP-Minnesota will continue to expense the incremental property taxes. An MPUC decision is expected in the second quarter of 2012.

Recently Concluded Regulatory Proceedings — North Dakota Public Service Commission (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, and a step increase of $4.2 million, or 2.6 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 $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.

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.

In September 2011, NSP-Minnesota reached a settlement with the NDPSC Advocacy Staff, which provided for 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 2012 sales coming in below forecast revenue projections, the settlement includes a true-up to 2012 non-fuel revenues plus the settlement rate increase. In February 2012, the NDPSC approved the settlement agreement.

Pending Regulatory Proceedings — South Dakota Public Utilities Commission (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. On Jan. 2, 2012, interim rates of $12.7 million were implemented.

In April 2012, the SDPUC Staff filed their direct testimony, which recommended an ROE of approximately 9 percent (ranging from 8.5 percent to 9.5 percent) and a lower cost of debt than the request (6.02 percent compared to the original request of 6.13 percent). The Staff also recommended disallowance of the Nobles wind project costs unless the SDPUC determines there is energy value in which case the Staff's recommendation would be to disallow a portion of the costs. NSP-Minnesota's rebuttal testimony is due by April 27, 2012 and a final SDPUC decision is expected in the summer of 2012.

PSCo

Recently Concluded Regulatory Proceedings — CPUC

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, an electric rate base of $5.4 billion and an equity ratio of 56 percent.

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On April 26, 2012, the CPUC approved a comprehensive multi-year settlement agreement, which covers 2012 through 2014. Key terms of the agreement include the following:

- PSCo will implement an annual electric rate increase of $73 million in 2012. The rate increase will be effective on May 1, 2012, subject to refund. In addition, PSCo will implement incremental electric rate increases of $16 million on Jan. 1, 2013 and $25 million on Jan. 1, 2014. These rate increases are net of the shift of the costs from the purchased capacity cost adjustment and the transmission cost adjustment clauses to base rates.
- The settlement reflects an authorized ROE of 10 percent and an equity ratio of 56 percent.
- PSCo will forego the opportunity allowed under the CACJA to seek additional rate mechanisms to recover approved CACJA plan costs through 2014. PSCo will instead recover the carrying costs of CACJA related expenditures through the recording of allowance for funds used during construction.
- For 2012 through 2014, incremental property taxes in excess of $76.7 million (2010-2011 historic test year property taxes) will be deferred over a three-year period with the amortization effective the first year after the deferral. To the extent that PSCo is successful in gaining the manufacturer’s sales tax refund as a result of the sales tax lawsuit currently pending in the Colorado Supreme Court, PSCo shall credit such refunds first against legal fees incurred to obtain the refund and then against the deferred property tax balances outstanding at the end of the 2014.
- The rates that take effect include no incremental recovery of deferred costs associated with the expiration of the Black Hills contract. However, the jurisdictional allocator used to determine the increase in base rates and for all rider calculations will reflect the expiration of the Black Hills contract as of Dec. 31, 2011. The rates that would take effect also include no change in depreciation rates.
- The signing parties agree to implement an earnings test, in which customers and shareholders will share earnings above an ROE of 10 percent. The sharing mechanism is as follows:

ROE	Shareholders	Customers
> 10.0% ≤ 10.2%	40 %	60 %
> 10.2% ≤ 10.5%	50	50
> 10.5%	-	100

- PSCo agrees that it will not file for an electric rate increase that would take effect prior to Jan. 1, 2015, provided that net revenue requirements increases or decreases in excess of $10 million caused by changes in tax law, government mandates, or natural disasters may be deferred or recovered through a modified rate adjustment. In the event normalized base revenues in either 2012 or 2013 are 2.0 percent below 2011 actual levels adjusted to reflect the rate increases allowed for 2012 and 2013, PSCo has the right to an additional rate adjustment in the next year for 50 percent of the shortfall. The parties acknowledge that PSCo may file an electric rate increase as early as May 1, 2014, so long as no rate increase takes effect on either an interim or permanent basis prior to Jan. 1, 2015.

Pending and Recently Concluded Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

PSCo 2011 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. In September 2011, PSCo implemented an interim rate increase of $7.8 million, subject to refund.

In April 2012, PSCo filed an unopposed settlement agreement with wholesale customers for an annual rate increase of $7.8 million. The primary reasons for the decrease from the original request were a reduction to depreciation expense of $5.8 million and a lower ROE (ranging from 10.1 percent to 10.4 percent). The reduction of depreciation expense is associated with the early retirement of plants related to PSCo’s compliance with the CACJA. The depreciation expense will be deferred and amortized over the original life of the plants.

PSCo Transmission Formula Rate Case — In April 2012, PSCo filed with the FERC to revise the wholesale transmission rates formula from a historic test year formula rate to a forecast transmission formula. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's transmission revenue by approximately $2.0 million over rates expected to be effective in June 2012. A FERC decision is expected in the second half of 2012.

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Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (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 renewable energy standard adjustment (RESA) regulatory asset balance. In the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

In the first quarter of 2012, the CPUC approved an annual 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. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. In March 2012, PSCo credited approximately $28.7 million against the RESA regulatory asset balance.

This sharing mechanism will be effective through 2014 to provide the CPUC an opportunity to review the framework and to review evidence regarding actual deliveries in relatively more complex markets such as California.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

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 utility 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 had approximately 3,773 megawatts (MW) of capacity under long-term purchased power agreements as of March 31, 2012 and Dec. 31, 2011 with entities that have been determined to be variable interest entities. 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. These agreements have expiration dates through the year 2033.

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 March 31, 2012 and Dec. 31, 2011, Xcel Energy Inc. and its subsidiaries have no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy Inc.:

(Millions of Dollars)	March 31, 2012	Dec. 31, 2011
Guarantees issued and outstanding	$67.5	$67.5
Current exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	30.4	31.2

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Indemnification Agreements

In connection with the acquisition of the 201 MW Nobles wind project in 2011, 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 of Calpine Development Holdings Inc. in 2010, 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

Manufactured Gas Plant (MGP) Sites

Ashland MGP Site — NSP-Wisconsin has been named a potentially responsible party (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 U.S. Environmental Protection Agency (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. In June 2011, NSP-Wisconsin submitted a settlement offer to the EPA related to the future cleanup of the Ashland site. In July 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, which are currently ongoing.

At March 31, 2012 and Dec. 31, 2011, NSP-Wisconsin had recorded a liability of $104.3 million, based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $26.6 million 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 Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized 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 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.

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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 eight 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 $4.0 million and $3.9 million at March 31, 2012 and Dec. 31, 2011, 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.

Other Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard Proposal (NSPS) and Emission Guideline for Existing Sources — The EPA plans to propose GHG regulations applicable to emissions from new and existing power plants under the Clean Air Act (CAA). In April 2012, the EPA proposed a GHG NSPS for newly constructed power plants. The proposal requires that carbon dioxide (CO2) emission rates be equal to those achieved by a natural gas combined cycle plant, even if the plant is coal-fired. The EPA also proposed that NSPS not apply to modified or reconstructed existing power plants and noted that, pursuant to its general NSPS regulations, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. It is not possible to evaluate the impact of this regulation until its final requirements are known. It is not known when the EPA will propose standards for existing sources.

New Mexico GHG Regulations — In 2010, the New Mexico Environmental Improvement Board (EIB) adopted two regulations to limit GHG emissions, including CO2 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 GHG rule with the EIB. The EIB repealed both regulations in February 2012 and in March 2012. In April 2012, Western Resource Advocates and New Energy Economy, Inc. filed an appeal with the New Mexico Court of Appeals to challenge the EIB's February decision to repeal the GHG cap-and-trade program rule. SPS has filed a petition to intervene in the appeal.

Cross-State Air Pollution Rule (CSAPR) — In July 2011, the EPA issued its CSAPR to address long range transport of particulate matter and ozone by requiring reductions in sulfur dioxide (SO2) and nitrogen oxide (NOx) from utilities located in the eastern half of the United States. For Xcel Energy, the rule applies to Minnesota, Wisconsin and Texas. The CSAPR sets more stringent requirements than the proposed Clean Air Transport Rule and specifically requires plants in Texas to reduce their SO2 and annual NOx emissions. The rule also creates an emissions trading program.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a stay of the CSAPR, pending completion of judicial review. Oral arguments in the case were held in April 2012 and it is anticipated the D.C. Circuit will 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 D.C. Circuit 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. On April 23, 2012, SPS appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under CSAPR. While this rule increases the allowance allocations for SO2 for SPS, it did not increase them by as much as the proposed rule. SPS is seeking additional allowance allocations through this appeal, which, if successful, would reduce SPS' costs to comply with the CSAPR.

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 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. On April 23, 2012, NSP-Minnesota appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under CSAPR, seeking to secure additional allocations for its Riverside and High Bridge plants. If successful, additional allowances would reduce NSP-Minnesota's costs to comply with the CSAPR.

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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.

Electric Generating Unit (EGU) Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. Xcel Energy believes these costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

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 best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas throughout the United States. 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 state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. In March 2012, the EPA proposed to approve the Colorado SIP, including the CACJA emission reduction plan for PSCo, as satisfying BART requirements. 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.

In March 2010, two environmental groups petitioned the U.S. Department of the Interior (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. The following 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 Minnesota Pollution Control Agency (MPCA) 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 Selective Catalytic Reduction (SCR) 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 that 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.

On April 24, 2012, the MPCA approved a supplement to the 2009 Regional Haze SIP finding that CSAPR meets BART for EGUs in Minnesota. The supplement also made a source-specific BART determination for Sherco Units 1 and 2 that requires installation of the combustion controls for NOx and scrubber upgrades for SO2 by January 2015. This SIP supplement will be forwarded to the EPA for approval, and it is anticipated that the EPA will make a decision in May 2012.

In addition to the Regional Haze rules identified in the EPA's visibility program, and addressed in the MPCA's SIP discussed above, there are other visibility rules related to a program called the Reasonably Attributable Visibility Impairment (RAVI) program. 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 RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program. It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail.

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SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a Regional Haze SIP that finds the Clean Air Interstate Rule (CAIR) equal to BART for EGUs, and as a result, no additional controls for these units beyond the CAIR compliance would be required. The EPA is scheduled to publish its proposal of the Texas plan in May 2012 and complete its review by November 2012.

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 consolidated financial position, results of operations, and cash flows.

Environmental 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 could potentially 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. — In May 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' CO2 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 filed a motion to dismiss the lawsuit. On March 20, 2012, the U.S. District Court granted this motion for dismissal. In April 2012, plaintiffs appealed this decision to the U.S. Court of Appeals for the Fifth Circuit. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially 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.

Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 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 of 2011, which was collected in April 2011. In May 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 and 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. In September 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 could potentially 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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7. Borrowings and Other Financing Instruments

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.

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 March 31, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	339	219
Average amount outstanding	324	430
Maximum amount outstanding	463	824
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at period end	0.36	0.40

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

At March 31, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility	Drawn (a)	Available
Xcel Energy Inc.	$ 800.0	$ 214.0	$ 586.0
PSCo	700.0	3.0	697.0
NSP-Minnesota	500.0	35.7	464.3
SPS	300.0	26.0	274.0
NSP-Wisconsin	150.0	71.0	79.0
Total	$ 2,450.0	$ 349.7	$ 2,100.3

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

All credit facility bank borrowings 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 March 31, 2012 and Dec. 31, 2011.

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 March 31, 2012 and Dec. 31, 2011, there were $10.7 million and $12.7 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 March 31, 2012 and Dec. 31, 2011, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

8. 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.

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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. Based on NSP-Minnesota's evaluation of its ability to redeem 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 — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, for which the third party service may also consider additional, more subjective inputs. Since the impact of the use of these less observable inputs can be significant to the valuation of asset-backed and mortgage-backed securities, fair value measurements for these instruments have been assigned a Level 3. Inputs that may be considered in the valuation of asset-backed and mortgage-backed securities in conjunction with pricing of similar securities in active markets include the use of risk-based discounting and estimated prepayments in a discounted cash flow model. When these additional inputs and models are utilized, increases in the risk-adjusted discount rates and decreases in the assumed principal prepayment rates each have the impact of reducing reported fair values for these instruments.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota include financial transmission rights (FTRs) purchased from Midwest Independent Transmission System Operator, Inc. (MISO). FTRs purchased from MISO are financial instruments that entitle the holder to one year of monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of that energy congestion, which is caused by overall transmission load and other transmission constraints. Congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Monthly FTR settlements are included in the fuel clause adjustment, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

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Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivatives, 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 derivative liabilities, the impact of considering credit risk was immaterial to the fair value of interest rate derivatives and commodity derivatives presented in the consolidated balance sheets.

Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (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 $117.1 million and $79.8 million at March 31, 2012 and Dec. 31, 2011, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $65.7 million and $87.5 million at March 31, 2012 and Dec. 31, 2011, 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 March 31, 2012 and Dec. 31, 2011:

		March 31, 2012 Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$12,383	$8,023	$4,360	$-	$12,383
Commingled funds	374,523	-	371,078	-	371,078
International equity funds	65,712	-	67,183	-	67,183
Private equity investments	19,358	-	-	20,068	20,068
Real estate	26,265	-	-	27,905	27,905
Debt securities:					
Government securities	131,152	-	131,401	-	131,401
U.S. corporate bonds	156,602	-	163,851	-	163,851
International corporate bonds	25,187	-	26,351	-	26,351
Municipal bonds	53,895	-	56,862	-	56,862
Asset-backed securities	16,515	-	-	16,547	16,547
Mortgage-backed securities	65,803	-	-	68,671	68,671
Equity securities:					
Common stock	410,729	447,205	-	-	447,205
Total	$1,358,124	$455,228	$821,086	$133,191	$1,409,505

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $92.3 million of equity investments in unconsolidated subsidiaries and $35.7 million of miscellaneous investments.

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		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.

The following tables present the changes in Level 3 nuclear decommissioning fund investments:

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	March 31, 2012
Asset-backed securities	$ 16,501	$ -	$ (1)	$ 47	$ 16,547
Mortgage-backed securities	78,664	6,904	(16,728)	(169)	68,671
Real estate	26,395	1,636	(1,766)	1,640	27,905
Private equity investments	9,203	10,155	-	710	20,068
Total	$ 130,763	$ 18,695	$ (18,495)	$ 2,228	$ 133,191

(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Losses Recognized as Regulatory Assets	March 31, 2011
Asset-backed securities	$ 33,174	$ 756	$ (7,910)	$ -	$ 26,020
Mortgage-backed securities	72,589	46,113	(19,873)	(462)	98,367
Total	$ 105,763	$ 46,869	$ (27,783)	$ (462)	$ 124,387

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at March 31, 2012:

	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	$113,004	$701	$17,696	$-	$131,401
U.S. corporate bonds	-	37,556	112,103	14,192	163,851
International corporate bonds	-	8,162	18,186	3	26,351
Municipal bonds	-	-	27,039	29,823	56,862
Asset-backed securities	-	13,269	3,278	-	16,547
Mortgage-backed securities	-	-	959	67,712	68,671
Debt securities	$113,004	$59,688	$179,261	$111,730	$463,683

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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 March 31, 2012, accumulated other comprehensive losses 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 March 31, 2012, 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.

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 March 31, 2012, 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 three months ended March 31, 2012 and 2011.

At March 31, 2012, 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.

The following table details the gross notional amounts of commodity forwards, options and FTRs at March 31, 2012 and Dec. 31, 2011:

(Amounts in Thousands) (a)(b)	Dec. 31, 2011

	March 31, 2012	
Megawatt hours (MWh) of electricity	23,385	38,822
MMBtu of natural gas	-	40,736
Gallons of vehicle fuel	550	600

(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.

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The following tables detail the impact of derivative activity during the three months ended March 31, 2012 and 2011, on OCI, regulatory assets and liabilities, and income:

	Three Months Ended March 31, 2012				
	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	$ 41,704	$ -	$ 389 (a)	$ -	$ -
Vehicle fuel and other commodity	179	-	(52)(e)	-	-
Total	$ 41,883	$ -	$ 337	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 1,723 (b)
Electric commodity	-	1,582	-	(7,972)(c)	-
Natural gas commodity	-	(10,783)	-	80,939 (d)	(109)(b)
Total	$ -	$ (9,201)	$ -	$ 72,967	$ 1,614

	Three Months Ended March 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 Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ -	$ -	$ 337 (a)	$ -	$ -
Vehicle fuel and other commodity	389	-	(32)(e)	-	-
Total	$ 389	$ -	$ 305	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 5,600 (b)
Electric commodity	-	8,846	-	(8,888)(c)	-

Natural gas commodity	-	(7,615)	-	57,387 (d)	-
Total	$ -	$ 1,231	$ -	$ 48,499	$ 5,600

(a) Recorded to interest charges.
(b) Recorded to electric operating revenues. Portions of these 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.

Xcel Energy had no derivative instruments designated as fair value hedges during the three months ended March 31, 2012 and March 31, 2011. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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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 utility subsidiaries were downgraded below investment grade, contracts underlying $10.8 million and $8.3 million of derivative instruments in a gross liability position at March 31, 2012 and Dec. 31, 2011, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $9.4 million and $9.3 million, respectively. At March 31, 2012 and Dec. 31, 2011, 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 March 31, 2012 and Dec. 31, 2011.

Recurring Fair Value Measurements — The following tables present for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at March 31, 2012:

	March 31, 2012					
		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:						
Interest rate	$-	$306	$-	$306	$ -	$306
Vehicle fuel and other commodity	-	208	-	208	-	208
Other derivative instruments:						
Trading commodity	-	39,483	-	39,483	(16,195)	23,288
Electric commodity	-	-	5,898	5,898	(570)	5,328
Total current derivative assets	$-	$39,997	$5,898	$45,895	$ (16,765)	29,130
Purchased power agreements (a)						32,841
Current derivative instruments						$61,971
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$209	$-	$209	$ (115)	$94
Other derivative instruments:						
Trading commodity	-	38,214	-	38,214	(5,470)	32,744
Total noncurrent derivative assets	$-	$38,423	$-	$38,423	$ (5,585)	32,838
Purchased power agreements (a)						113,600
Noncurrent derivative instruments						$146,438

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	March 31, 2012					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$-	$16,352	$-	$16,352	$ -	$16,352
Other derivative instruments:						
Trading commodity	-	34,130	4	34,134	(17,272)	16,862
Electric commodity	-	-	570	570	(570)	-
Total current derivative liabilities	$-	$50,482	$574	$51,056	$ (17,842)	33,214
Purchased power agreements (a)						22,918
Current derivative instruments						$56,132
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$22,918	$-	$22,918	$ (5,585)	$17,333
Total noncurrent derivative liabilities	$-	$22,918	$-	$22,918	$ (5,585)	17,333
Purchased power agreements (a)						242,819
Noncurrent derivative instruments						$260,152

(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 tables present 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:						
	$-	$169	$-	$169	$ (76)	$93

Vehicle fuel and other commodity						
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.

The following table presents the changes in Level 3 commodity derivatives for the three months ended March 31, 2012 and 2011:

(Thousands of Dollars)	Three Months Ended March 31 2012	2011
Balance at Jan. 1	$ 12,417	$ 2,392
Settlements	(8,884)	(7,790)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings (a)	(9)	68
Gains recognized as regulatory liabilities	1,800	7,662

Balance at March 31	$ 5,324	$ 2,332

(a) These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for the three months ended March 31, 2012 and March 31, 2011.

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Fair Value of Long-Term Debt

As of March 31, 2012 and Dec. 31, 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	March 31, 2012		Dec. 31, 2011	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 9,908,044	$ 11,414,894	$ 9,908,435	$ 11,734,798

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of March 31, 2012 and Dec. 31, 2011, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since those dates and current estimates of fair values may differ significantly.

9. Other Income, Net

Other income (expense), net consisted of the following:

	Three Months Ended March 31	
(Thousands of Dollars)	2012	2011
Interest income	$ 5,622	$ 4,773
Other nonoperating income	922	864
Insurance policy expense	(2,799)	(871)
Other nonoperating expense	(8)	-
Other income, net	$ 3,737	$ 4,766

10. Segment 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.

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 $92.3 million and $92.7 million as of March 31, 2012 and Dec. 31, 2011, 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.

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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.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2012					
Operating revenues from external customers	$1,936,782	$621,035	$20,262	$ -	$ 2,578,079
Intersegment revenues	302	499	-	(801)	-
Total revenues	$1,937,084	$621,534	$20,262	$ (801)	$ 2,578,079
Income (loss) from continuing operations	$143,221	$50,202	$(9,654)	$ -	$ 183,769

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended March 31, 2011					
Operating revenues from external customers	$2,029,972	$765,349	$21,219	$ -	$ 2,816,540
Intersegment revenues	339	799	-	(1,138)	-
Total revenues	$2,030,311	$766,148	$21,219	$ (1,138)	$ 2,816,540
Income (loss) from continuing operations	$154,637	$58,597	$(9,767)	$ -	$ 203,467

11. Earnings Per Share

Basic earnings per share (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 share-based compensation awards were settled. 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.

Share-Based Compensation

Common stock equivalents related to share-based compensation causing dilutive impact to EPS currently consist of 401(k) equity awards. 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.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Restricted stock unit 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.
- Performance share plan liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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The dilutive impact of common stock equivalents affecting EPS was as follows:

(Amounts in thousands, except per share data)	Three Months Ended March 31, 2012 Income	Shares	Per Share Amount	Three Months Ended March 31, 2011 Income	Shares	Per Share Amount
Net income	$183,893			$203,569		
Less: Dividend requirements on preferred stock	-			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	183,893	487,360	$0.38	202,509	483,641	$0.42
Effect of dilutive securities:						
401(k) equity awards	-	635		-	660	
Diluted earnings per share:						
Earnings available to common shareholders	$183,893	487,995	$0.38	$202,509	484,301	$0.42

For the three months ended March 31, 2011, Xcel Energy Inc. had approximately 2.5 million weighted average stock options outstanding that were antidilutive, and therefore, excluded from the EPS calculation. No stock options were outstanding at March 31, 2012.

Share Repurchase — In February 2012, Xcel Energy Inc.'s Board of Directors approved the repurchase of up to 0.7 million shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. In March 2012, Xcel Energy Inc. repurchased the approved 0.7 million shares in the open market at an average price of $26.42 per share. In addition, approximately 0.9 million shares of common stock were purchased in February 2012 through an agent independent of Xcel Energy to fulfill requirements for the employer match pursuant to the Xcel Energy 401(k) Savings Plan; the New Century Energies, Inc. Employees' Savings and Stock Ownership Plan for Bargaining Unit Employees and Former Non-Bargaining Unit Employees; and the New Century Energies, Inc. Employee Investment Plan for Bargaining Unit Employees and Non-Bargaining Employees.

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended March 31			
	2012	2011	2012	2011
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$21,329	$18,112	$1,180	$1,315
Interest cost	38,723	39,915	9,380	10,551
Expected return on plan assets	(51,476)	(55,286)	(7,111)	(7,968)
Amortization of transition obligation	-	-	3,580	3,611
Amortization of prior service cost (credit)	5,266	5,633	(1,888)	(1,233)
Amortization of net loss	26,318	18,729	3,965	3,343
Net periodic benefit cost	40,160	27,103	9,106	9,619
Costs not recognized and additional cost recognized due to the effects of regulation	(9,133)	(7,885)	973	973
Net benefit cost recognized for financial reporting	$31,027	$19,218	$10,079	$10,592

In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2012.

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Item 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

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 in reports filed with the SEC, including "Risk Factors" in Item 1A of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2011, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.

Financial Review

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:

	Three Months Ended March 31	
Diluted Earnings (Loss) Per Share	2012	2011
PSCo	$ 0.19	$ 0.20
NSP-Minnesota	0.16	0.19
NSP-Wisconsin	0.03	0.03
SPS	0.02	0.02
Equity earnings of unconsolidated subsidiaries	0.01	0.01
Regulated utility — continuing operations	0.41	0.45
Xcel Energy Inc. and other costs	(0.03)	(0.03)
GAAP diluted earnings per share	$ 0.38	$ 0.42

Xcel Energy — Overall, earnings decreased $0.04 per share for the first quarter of 2012.

PSCo — PSCo earnings decreased $0.01 per share for the first quarter of 2012. The decrease is mainly due to lower electric and gas sales due to warmer weather, decreased wholesale revenue due to the expiration of a long-term wholesale power agreement with Black Hills Corp., higher depreciation expense and interest charges, partially offset by higher gas revenues, primarily due to new rates effective in September 2011.

NSP-Minnesota — NSP-Minnesota earnings decreased $0.03 per share for the first quarter of 2012. The decrease is primarily the result of warmer weather impacting electric and gas sales, differences between rates effective in the first quarter of 2012 as compared to interim rates in the first quarter of 2011, higher property taxes and higher O&M expenses. The decreases were partially offset by a lower effective tax rate.

NSP-Wisconsin — NSP-Wisconsin earnings per share were flat for the first quarter of 2012. Higher electric and gas rates implemented in January 2012 and lower O&M expenses were offset by lower electric and gas sales due to warmer weather.

SPS — SPS earnings per share were flat for the first quarter of 2012. Higher electric margins in Texas and New Mexico, primarily due to rate increases effective in January 2012, were offset by the negative impact of warmer weather, higher depreciation expense, property taxes and interest charges.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in the 2012 EPS compared with the same period in 2011, which are discussed in more detail below.

Diluted Earnings (Loss) Per Share	Three Months Ended March 31
2011 GAAP diluted earnings per share	$ 0.42
Components of change — 2012 vs. 2011	
Lower electric margins	(0.03)
Lower natural gas margins	(0.02)
Higher interest charges	(0.01)
Higher taxes (other than income taxes)	(0.01)

Lower effective tax rate		0.03
Lower conservation and DSM expenses (generally offset in revenues)		0.01
Other, net		(0.01)
2012 GAAP diluted earnings per share	$	0.38

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The following tables summarize the earnings contributions of Xcel Energy's business segments on the basis of GAAP:

Contributions to Income (Millions of Dollars)	Three Months Ended March 31 2012	Three Months Ended March 31 2011
GAAP income (loss) by segment		
Regulated electric income	$ 143.2	$ 154.6
Regulated natural gas income	50.2	58.6
Other income (a)	7.3	5.0
Segment income — continuing operations	200.7	218.2
Xcel Energy Inc. and other costs (a)	(16.9)	(14.7)
Total income — continuing operations	183.8	203.5
Income from discontinued operations	0.1	0.1
Total GAAP net income	$ 183.9	$ 203.6

Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended March 31 2012	Three Months Ended March 31 2011
GAAP earnings (loss) by segment		
Regulated electric	$ 0.29	$ 0.32
Regulated natural gas	0.10	0.12
Other (a)	0.02	0.01
Segment earnings per share — continuing operations	0.41	0.45
Xcel Energy Inc. and other costs(a)	(0.03)	(0.03)
Total earnings per share — continuing operations	0.38	0.42
Discontinued operations	-	-
Total GAAP earnings per diluted share	$ 0.38	$ 0.42

(a)Not a reportable segment. Included in all other segment results in Note 10 to the consolidated financial statements.

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 — Unusually 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.

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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.

There was no impact on sales in the first quarter due to THI or CDD. The percentage increase (decrease) in normal and actual HDD is provided in the following table:

	Three Months Ended March 31		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
HDD	(18.7)%	5.2 %	(22.1)%

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

	Three Months Ended March 31		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
Retail electric	$(0.023)	$0.007	$(0.030)
Firm natural gas	(0.021)	0.007	(0.028)
Total	$(0.044)	$0.014	$(0.058)

Sales Growth (Decline) — The following table summarizes Xcel Energy's sales growth (decline) for actual and weather-normalized sales in 2012:

	Three Months Ended March 31		Three Months Ended March 31 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(5.1)%	0.5 %	(6.1)%	(0.6)%
Electric commercial and industrial	(0.7)	0.2	(1.8)	(0.9)
Total retail electric sales	(2.0)	0.3	(3.1)	(0.8)
Firm natural gas sales	(14.7)	1.3	(15.7)	0.2

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:

	Three Months Ended March 31	
(Millions of Dollars)	2012	2011
Electric revenues	$1,937	$2,030
Electric fuel and purchased power	(864)	(932)
Electric margin	$1,073	$1,098

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The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)		Three Months Ended March 31, 2012 vs. 2011
Fuel and purchased power cost recovery	$	(65)
Estimated impact of weather		(22)
Firm wholesale (a)		(13)
Trading, including PSCo renewable energy credit sales		(7)
Conservation and DSM revenue (offset by expenses)		(4)
Transmission revenue		10
Retail rate increases (Minnesota, Texas, New Mexico, South Dakota interim, North Dakota, Wisconsin and Michigan) (b)		5
Sales mix and demand revenue		2
Conservation and DSM incentive		2
Other, net		(1)
Total decrease in electric revenues	$	(93)

(a) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the first quarter of 2012 to reflect the settlement in the Minnesota electric rate case.

Electric Margin

(Millions of Dollars)		Three Months Ended March 31, 2012 vs. 2011
Estimated impact of weather	$	(22)
Firm wholesale (a)		(11)
Conservation and DSM revenue (offset by expenses)		(4)
Transmission revenue, net of costs		5
Retail rate increases (Minnesota, Texas, New Mexico, South Dakota interim, North Dakota, Wisconsin and Michigan) (b)		5
Sales mix and demand revenue		2
Conservation and DSM incentive		2
Other, net		(2)
Total decrease in electric margin	$	(25)

(a) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the first quarter of 2012 to reflect the settlement in the Minnesota electric rate case.

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:

	Three Months Ended March 31,	
(Millions of Dollars)	2012	2011
Natural gas revenues	$621	$765
Cost of natural gas sold and transported	(418)	(543)
Natural gas margin	$203	$222

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The following tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Purchased natural gas adjustment clause recovery	$ (125)
Estimated impact of weather	(21)
Conservation and DSM revenue (offset by expenses)	(9)
Retail rate increase (Colorado, Wisconsin)	3
Pipeline system integrity adjustment rider (Colorado)	3
Return on PSCo gas in storage	2
Conservation and DSM incentive	1
Other, net	2
Total decrease in natural gas revenues	$ (144)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Estimated impact of weather	$ (21)
Conservation and DSM revenue (offset by expenses)	(9)
Retail rate increase (Colorado, Wisconsin)	3
Pipeline system integrity adjustment rider (Colorado)	3
Return on PSCo gas in storage	2
Conservation and DSM incentive	1
Other, net	2
Total decrease in natural gas margin	$ (19)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $0.7 million, or 0.1 percent, for the first quarter of 2012, compared with the same period in 2011. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended March 31, 2012 vs. 2011
Higher plant generation costs	$ 6
Pipeline system integrity costs	3
Lower consulting costs	(3)
Lower employee benefit expense	(2)
Other, net	(3)
Total increase in O&M expenses	$ 1

- Higher plant generation costs are attributable to a higher level of scheduled overhaul work.
- Higher pipeline system integrity costs were for verification and testing natural gas pipeline integrity. These costs are recovered through a rider in Colorado.

- Lower employee benefit expenses were driven by lower compensation and incentive expenses, partially offset by higher pension expense.

Conservation and DSM Program Expenses — Conservation and demand side management (DSM) program expenses decreased $11.6 million, or 15.4 percent for the first quarter of 2012, compared with the same period in 2011. The lower expense is primarily attributable to lower sales volumes and lower rider rates, as well as a change in the cost allocation formula used to account for electric conservation improvement program expenses at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

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Depreciation and Amortization — Depreciation and amortization increased $3.9 million, or 1.8 percent for the first quarter of 2012, compared with the same period in 2011. This increase is primarily due to a portion of the Monticello extended power uprate going into service in May 2011 at NSP-Minnesota, the Jones Unit 3 going into service in June 2011 at SPS and normal system expansion across Xcel Energy's service territories. The increase was partially offset by a change in depreciation lives for certain assets to reflect the settlement in the Minnesota recent electric rate case, which resulted in a reduction in depreciation expense of approximately $8 million.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $9.1 million, or 9.4 percent for the first quarter of 2012, compared with the same period in 2011. The increase is primarily due to an increase in property taxes in Minnesota. NSP-Minnesota has requested to defer incremental property taxes in Minnesota effective as of Jan. 1, 2012. However, until the MPUC rules on this issue, NSP-Minnesota will continue to expense the incremental property taxes. Assuming MPUC approval of NSP-Minnesota's request, which is currently expected in the second quarter of 2012, NSP-Minnesota would reflect the deferral retroactive to Jan. 1, 2012. See Note 5 to the consolidated financial statements for further discussion.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC decreased $0.6 million, or 3.0 percent for the first quarter of 2012, compared with the same period in 2011. The decrease is primarily due to lower average construction work in progress balances.

Interest Charges — Interest charges increased $7.5 million, or 5.2 percent for the first quarter of 2012, compared with the same period in 2011. The increase is due to higher long-term debt levels to fund investments in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations decreased $36.5 million for the first quarter of 2012, compared with the same period in 2011. The decrease in income tax expense was primarily due to lower pretax earnings and a tax benefit associated with a carryback. The effective tax rate for continuing operations was 29.1 percent for the first quarter of 2012 compared with 35.5 percent for the same period in 2011. The lower effective tax rate for 2012 was primarily due to the completion of an analysis in the first quarter on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result, Xcel Energy recognized a discrete tax benefit of approximately $15 million. Without this tax benefit, the effective tax rate for continuing operations for the first quarter of 2012 would have been 34.9 percent.

Factors Affecting Results of Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs in Item 1 in Xcel Energy Inc.'s Annual Report on Form 10-K filed for the year ended Dec. 31, 2011.

Public Utility Regulation

NSP-Minnesota

NSP-Minnesota CapX2020 Certificate of Need (CON) — In 2009, the MPUC granted CONs to construct one 230 kilovolt (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 Certificate of Public Convenience and Necessity (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, the Brookings, S.D. project, and the Bemidji, Minn. to Grand Rapids, Minn. project. In April 2012, the MPUC approved the route permit for the portions of the new transmission lines between Hampton, Minn. and La Crosse, Wis. to be constructed in Minnesota. The remaining required permit activities are ongoing in North Dakota and Wisconsin.

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 a multi-value project (MVP).

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NSP-Wisconsin

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 triggered the 360-day deadline for the PSCW to approve a CPCN for the project. Technical and public hearings were held in March 2012. PSCW Staff testimony supported the need for the project, both on a local and regional basis. The majority of the technical hearings covered issues regarding the various route alternatives. A PSCW final decision regarding the need and route locations is expected in June 2012.

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 North American Electric Reliability Corporation 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. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In July 2011, the FERC issued Order 1000 adopting new requirements for transmission planning, cost allocation, and development. On April 18, 2012, the Minnesota Governor signed legislation that preserves the rights of incumbent utilities to construct and own transmission interconnected to their systems. This legislation is similar to the legislation previously passed in North Dakota and South Dakota. Therefore, Order 1000 is expected to have very limited impacts on future transmission development and ownership in the NSP System in Minnesota, North Dakota, and the South Dakota. The impacts of the new requirements relating to future transmission development and ownership in Wisconsin are uncertain. Compliance filings to address these new requirements are due October 2012 and are effective prospectively. Motions for rehearing are pending action by the FERC.

La Crosse, Wis. to Madison, Wis. Transmission Line Complaint — In February 2012, Xcel Energy Inc. and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. The complaint states that MISO has determined that the line is to be owned by Xcel Energy and American Transmission Company LLC (ATC) under the terms of the MISO Transmission Owners Agreement (TOA) and Tariff; however, ATC has a different interpretation of the tariff provisions that would effectively deny NSP-Wisconsin the ability to invest $175 million in the proposed MVP, which Xcel Energy Inc. and NSP-Wisconsin believe will lower the overall cost of the project. The complaint requests the FERC rule by June 2012 that ATC has not complied with the TOA and Tariff, which are subject to the FERC regulation. The timing and ultimate resolution of the complaint are unknown.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 for further discussion regarding the nuclear generating plants. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

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 that has developed 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. On July 12, 2011, the task force released its recommendations in a written report. The report confirms the safety of U.S. nuclear energy facilities and recommends actions to enhance U.S. nuclear plant readiness to safely manage severe events. 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 to integrate and coordinate the industry's ongoing responses.

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In March 2012, the NRC issued three orders and a request for additional information to all licensees. The orders included requirements for mitigation strategies for beyond design basis external events, requirements with regard to reliable spent fuel instrumentation, and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The request for additional information included requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards, and to assess the emergency preparedness staffing and communications capabilities at each plant. The requirements were consistent with the approach proposed by the industry and is expected to result in NSP-Minnesota spending approximately $20 to $50 million to comply with the requirements at the Monticello and Prairie Island plants. NSP-Minnesota is evaluating the information requests and orders and expects to fully comply. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance begin in the second quarter of 2015 with all units being fully compliant by December 2016. NSP-Minnesota believes the costs associated with compliance 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.

Nuclear Plant Power Uprates

Prairie Island Nuclear Extended Power Uprate — In 2009, the MPUC approved a CON for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2. Recent analysis of the extended power uprate submittals to the NRC concluded that significant additional design work beyond NSP-Minnesota's estimated schedule and cost plan would be required for a successful application submittal. As a result, NSP-Minnesota completed an economic and new project design analysis and submitted a Change in Circumstances filing with the MPUC in March 2012. NSP-Minnesota asked the MPUC to confirm that the extended power uprate project is in the best interest of customers prior to NSP-Minnesota making the significant investments necessary to complete an application and undertake the NRC licensing process. The updated analysis shows the project continues to show system benefits, however the magnitude of the benefits is substantially lower than originally anticipated. An MPUC decision is expected in the first half of 2013.

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 expects to submit an update to the application for approval to the NRC in the fourth quarter of 2012, which could result in approval of the extended power uprate project by the NRC in the second quarter of 2013. NSP-Minnesota is planning to implement the equipment changes needed to support the Monticello life extension and power uprate projects in the planned spring 2013 refueling outage.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters in Note 6 to the consolidated financial statements.

Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. Item 7 — Management's Discussion and Analysis, in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, includes a discussion of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and that require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. As of March 31, 2012, there have been no material changes to policies set forth in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011.

Pending Accounting Changes

See a discussion of recently issued accounting pronouncements and pending accounting changes in Note 2 to the consolidated financial statements.

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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 8 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 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 were as follows:

	Three Months Ended March 31	
(Thousands of Dollars)	2012	2011
Fair value of commodity trading net contract assets outstanding at Jan. 1	$20,424	$20,249
Contracts realized or settled during the period	(3,261)	(1,668)
Commodity trading contract additions and changes during period	3,482	5,902
Fair value of commodity trading net contract assets outstanding at March 31	$20,645	$24,483

At March 31, 2012, the fair values by source for the commodity trading net asset balances were as follows:

(Thousands of Dollars)	Futures/ Forwards Source of	Maturity	Maturity	Maturity	Maturity

	Fair Value	Less Than 1 Year	1 to 3 Years	4 to 5 Years	Greater Than 5 Years	Total Futures/ Forwars Fair Value
NSP-Minnesota	1	$4,878	$14,377	$366	$-	$19,621
PSCo	1	471	553	-	-	1,024
		$5,349	$14,930	$366	$-	$20,645

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

At March 31, 2012, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact to pretax income from continuing operations.

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.

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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)	Period Ended March 31	VaR Limit	Average	High	Low
2012	$ 0.43	$ 3.00	$ 0.20	$ 0.92	$ 0.06
2011	0.30	3.00	0.17	0.30	0.10

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 March 31, 2012, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million related to expected 2012 debt issuances.

At March 31, 2012, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $4.1 million annually. See Note 8 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 March 31, 2012, 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 March 31, 2012, a 10 percent increase in prices would have resulted in a decrease in credit exposure of $7.5 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $7.9 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.

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 8 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 March 31, 2012. 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 March 31, 2012.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs and forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent immaterial percentages of total assets and liabilities measured at fair value at March 31, 2012.

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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 $5.9 million and $0.6 million of estimated fair values, respectively, for FTRs held at March 31, 2012.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility 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 March 31, 2012.

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 active market inputs are utilized to estimate the fair value of asset-backed and mortgage-backed securities. However, less observable and subjective inputs that may be used in conjunction with available pricing of similar securities in active markets can be significant to these valuations. These inputs include estimated principal prepayments and risk-based adjustments to the interest rate used to discount expected future cash flows in a discounted cash flow model. Given the potential significant impacts that unobservable inputs may have on the valuations of asset-backed and mortgage-backed securities, and based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $133.2 million in the nuclear decommissioning fund at March 31, 2012 (approximately 9.0 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.

Liquidity and Capital Resources

Cash Flows

	Three Months Ended March 31	
(Millions of Dollars)	2012	2011
Cash provided by operating activities	$ 477	$ 659

Net cash provided by operating activities decreased by $182 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011. The decrease was primarily related to lower net income, higher pension contributions and the effect of the income taxes paid in 2012 compared to the refund received in 2011.

	Three Months Ended March 31	
(Millions of Dollars)	2012	2011
Cash used in investing activities	$ (399)	$ (624)

Net cash used in investing activities decreased by $225 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011 The decrease was due, in part, to progress payments made in 2011 for the Merricourt wind project, higher 2011 capital expenditures, primarily related to amounts associated with the Jones Plant site in Lubbock, Texas, as well as timing of payments, and the change in restricted cash due to customer refunds associated with the nuclear waste disposal settlement with the U.S. Department of Energy.

	Three Months Ended March 31	
(Millions of Dollars)	2012	2011

Cash used in financing activities	$ (39)	$ (49)

Net cash used in financing activities decreased by $10 million for the three months ended March 31, 2012, compared with the three months ended March 31, 2011. The decrease was primarily due to higher proceeds from short-term borrowings, partially offset by repurchases of common stock and higher dividend payments.

Capital Requirements

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

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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 Regional Transmission Organization (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. For future years, we anticipate contributions will be made as necessary.

Capital Sources

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 March, 31, 2012, approximately $3.3 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. 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.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended	Twelve Months Ended

	March 31, 2012	Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	339	219
Average amount outstanding	324	430
Maximum amount outstanding	463	824
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at period end	0.36	0.40

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Credit Facilities — During March of 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed 4-year credit agreements. The total capacity of the credit facilities increased approximately $273 million to $2.45 billion. As of April 23, 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	$227.0	$573.0	$1.0	$574.0
PSCo	700.0	3.0	697.0	0.2	697.2
NSP-Minnesota	500.0	22.7	477.3	1.1	478.4
SPS	300.0	53.0	247.0	1.1	248.1
NSP-Wisconsin	150.0	80.0	70.0	0.7	70.7
Total	$2,450.0	$385.7	$2,064.3	$4.1	$2,068.4

(a) These credit facilities expire in 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.

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. Xcel Energy Inc. and its utility subsidiaries anticipate issuing the 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's 2012 earnings is expected to be in the lower half of the guidance range of $1.75 to $1.85 per share. Key assumptions related to earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings, including the MPUC's approval of our request to defer incremental property tax increases in 2012.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales are projected to be relatively flat.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Rider revenue recovery is projected to increase approximately $35 million to $45 million over 2011 levels.
- O&M expenses are projected to increase up to 1.0 percent over 2011 levels.
- Depreciation expense is projected to increase $50 million to $60 million over 2011 levels.
- Property taxes are projected to be relatively flat. This assumes the MPUC approves NSP-Minnesota's request to defer incremental 2012 property taxes in Minnesota.
- Interest expense (net of AFUDC — debt) is projected to increase approximately $10 million.
- AFUDC — equity is projected to increase approximately $10 million to $20 million over 2011 levels.
- The effective tax rate is projected to be approximately 34 percent to 35 percent.
- Average common stock and equivalents are projected to be approximately 488 million shares.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

Item 4 — 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 March 31, 2012, 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 Control 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.

Part II — OTHER INFORMATION

Item 1 — 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 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Note 5 to the consolidated financial statements for discussion of proceedings involving utility rates and other regulatory matters.

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Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2011, which is incorporated herein by reference.

Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

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
Jan. 1, 2012 — Jan. 31, 2012 (a)	17,487	$ 26.69	-	-
Feb. 1, 2012 — Feb. 29, 2012	-	-	-	-
March 1, 2012 — March 31, 2012 (b)	700,000	26.42	-	-
Total	717,487		-	-

(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 Xcel Energy Inc. Board of Directors approved the repurchase of up to 700,000 shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. Purchases were authorized to be made in the open market pursuant to Rule 10b-18.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05). On Jan. 1, 2012, Xcel Energy implemented the requirements of ASU No. 2011-05 by presenting net income, the components of OCI and total comprehensive income in two separate, but consecutive financial statements of net income and comprehensive income. The implementation resulted in more prominent presentation of total comprehensive income and more detailed presentation of the components of OCI.

The following presents retrospective application of ASU No. 2011-05 to the consolidated financial statements of Xcel Energy Inc. and subsidiaries, as a separate but consecutive statement following Xcel Energy Inc. and subsidiaries' consolidated statements of income for the years ended Dec. 31, 2011, 2010 and 2009. The financial statement presentation requirements of ASU No. 2011-05 do not affect the items previously reported in net income, OCI or total comprehensive income, or the guidance for reclassifying components of OCI to net income, and therefore retrospective application of the new guidance does not result in significant changes to the information reported in the previously issued financial statements.

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Thousands of Dollars)	Year Ended Dec. 31 2011	2010	2009
Net income	$841,172	$755,834	$680,887
Other comprehensive (loss) income			
Pension and retiree medical benefits:			
Net pension and retiree medical benefit losses arising during the period, net of tax of $(4,442), $(2,647) and $(3,215), respectively	(6,367)	(3,606)	(4,604)
Amortization of losses included in net periodic benefit cost, net of tax of $2,195, $1,231 and $1,012, respectively	3,162	1,751	1,475
	(3,205)	(1,855)	(3,129)
Derivative instruments:			
Net fair value decrease, net of tax of $(25,086), $(3,159) and $(843), respectively	(38,292)	(4,289)	(710)
Reclassification of losses to net income, net of tax of $598, $1,951 and $5,067, respectively	648	2,630	7,388
	(37,644)	(1,659)	6,678
Marketable securities:			
Net fair value (decrease) increase, net of tax of $(63), $89 and $284, respectively	(93)	130	411
Other comprehensive (loss) income	(40,942)	(3,384)	3,960
Comprehensive income	$800,230	$752,450	$684,847

Xcel Energy also files condensed financial statements of the parent company, Xcel Energy Inc., in its Form 10-K as Schedule I. The statements of comprehensive income above presenting retroactive application of ASU No. 2011-04 to Xcel Energy Inc. and subsidiaries are identical to those of the parent company.

Item 6 — EXHIBITS

* Indicates incorporation by reference

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)).
31.01	Principal Executive Officer's certifications 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 certifications 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 Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

April 27, 2012

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Vice President and Controller
(Principal Accounting Officer)

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)