XCEL ENERGY INC
Form 10-Q
October 26, 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 September 30, 2012
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number: 001-3034

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 £
Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company £

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 Oct. 18, 2012
Common Stock, $2.50 par value	487,619,543 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 Sept. 30		Nine Months Ended Sept. 30	
	2012	2011	2012	2011
Operating revenues				
Electric	$2,532,709	$2,619,424	$6,506,320	$6,777,793
Natural gas	174,513	194,930	1,016,861	1,251,817
Other	17,119	17,244	53,907	56,750
Total operating revenues	2,724,341	2,831,598	7,577,088	8,086,360
Operating expenses				
Electric fuel and purchased power	1,006,830	1,150,252	2,725,183	3,071,493
Cost of natural gas sold and transported	49,739	87,107	557,444	793,539
Cost of sales — other	7,251	7,154	20,499	22,100
Operating and maintenance expenses	531,480	532,962	1,576,178	1,575,159
Conservation and demand side management program expenses	68,920	71,280	191,242	212,075
Depreciation and amortization	239,051	242,329	694,364	696,316
Taxes (other than income taxes)	100,636	89,018	305,892	278,077
Total operating expenses	2,003,907	2,180,102	6,070,802	6,648,759
Operating income	720,434	651,496	1,506,286	1,437,601
Other income, net	488	2,550	4,953	8,295
Equity earnings of unconsolidated subsidiaries	7,490	7,423	22,150	22,813
Allowance for funds used during construction — equity	15,860	11,840	44,504	38,690
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,010, $6,279, $18,126 and $17,724, respectively	153,719	148,011	457,470	438,703
Allowance for funds used during construction — debt	(10,439)	(6,301)	(24,729)	(21,575)
Total interest charges and financing costs	143,280	141,710	432,741	417,128
Income from continuing operations before income taxes	600,992	531,599	1,145,152	1,090,271
Income taxes	202,845	193,304	380,161	389,838
Income from continuing operations	398,147	338,295	764,991	700,433
(Loss) income from discontinued operations, net of tax	(41)	37	68	230
Net income	398,106	338,332	765,059	700,663
Dividend requirements on preferred stock	-	1,414	-	3,534
Premium on redemption of preferred stock	-	3,260	-	3,260
Earnings available to common shareholders	$398,106	$333,658	$765,059	$693,869
Weighted average common shares outstanding:				
Basic	488,084	485,344	487,722	484,640

Diluted	488,578	485,894	488,198	485,152
Earnings per average common share:				
Basic	$0.82	$0.69	$1.57	$1.43
Diluted	0.81	0.69	1.57	1.43
Cash dividends declared per common share	$0.27	$0.26	$0.80	$0.77

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2012	2011	2012	2011
Net income	$398,106	$338,332	$765,059	$700,663
Other comprehensive loss				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $636, $515, $1,905 and $1,591, respectively	911	743	2,738	2,290
Derivative instruments:				
Net fair value decrease, net of tax of $(5,913), $(20,292), $(12,586) and $(20,188), respectively	(8,853)	(30,947)	(19,188)	(30,740)
Reclassification of losses to net income, net of tax of $296, $150, $610 and $438, respectively	393	159	756	464
	(8,460)	(30,788)	(18,432)	(30,276)
Marketable securities:				
Net fair value (decrease) increase, net of tax of $(30), $41, $89 and $76, respectively	(45)	59	129	110
Other comprehensive loss	(7,594)	(29,986)	(15,565)	(27,876)
Comprehensive income	$390,512	$308,346	$749,494	$672,787

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

	Nine Months Ended Sept. 30	
	2012	2011
Operating activities		
Net income	$765,059	$700,663
Remove income from discontinued operations	(68)	(230)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	707,630	709,936
Conservation and demand side management program amortization	5,511	7,979
Nuclear fuel amortization	79,171	75,292
Deferred income taxes	440,413	389,355
Amortization of investment tax credits	(4,656)	(4,740)
Allowance for equity funds used during construction	(44,504)	(38,690)
Equity earnings of unconsolidated subsidiaries	(22,150)	(22,813)
Dividends from unconsolidated subsidiaries	24,922	25,481
Share-based compensation expense	20,886	31,943
Net realized and unrealized hedging and derivative transactions	(90,123)	14,537
Changes in operating assets and liabilities:		
Accounts receivable	(125,803)	(33,649)
Accrued unbilled revenues	166,857	155,854
Inventories	55,511	(47,207)
Other current assets	(30,289)	60,216
Accounts payable	(118,276)	(82,681)
Net regulatory assets and liabilities	1,848	134,338
Other current liabilities	(35,283)	5,969
Pension and other employee benefit obligations	(181,281)	(136,538)
Change in other noncurrent assets	(38,790)	21,211
Change in other noncurrent liabilities	(4,664)	(42,108)
Net cash provided by operating activities	1,571,921	1,924,118
Investing activities		
Utility capital/construction expenditures	(1,805,843)	(1,604,206)
Proceeds from insurance recoveries	56,892	-
Merricourt refund	-	101,261
Merricourt deposit	-	(90,833)
Allowance for equity funds used during construction	44,504	38,690
Purchases of investments in external decommissioning fund	(501,009)	(1,741,907)
Proceeds from the sale of investments in external decommissioning fund	501,009	1,741,909
Investment in WYCO Development LLC	(779)	(1,768)
Change in restricted cash	95,287	(99,972)
Other, net	343	(4,129)
Net cash used in investing activities	(1,609,596)	(1,660,955)
Financing activities		
Proceeds from (repayments of) short-term borrowings, net	85,000	(416,400)

Proceeds from issuance of long-term debt	1,691,322	688,686
Repayments of long-term debt, including reacquisition premiums	(653,532)	(104,525)
Proceeds from issuance of common stock	5,878	6,164
Repurchase of common stock	(18,529)	-
Purchase of common stock for settlement of equity awards	(23,307)	-
Dividends paid	(362,568)	(351,370)
Net cash provided by (used in) financing activities	724,264	(177,445)
Net change in cash and cash equivalents	686,589	85,718
Cash and cash equivalents at beginning of period	60,684	108,437
Cash and cash equivalents at end of period	$747,273	$194,155
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(436,296)	$(405,111)
Cash (paid) received for income taxes, net	(6,257)	53,567
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$229,847	$136,236
Issuance of common stock for reinvested dividends and 401(k) plans	51,350	55,319

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

	Sept. 30, 2012	Dec. 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$747,273	$60,684
Restricted cash	-	95,287
Accounts receivable, net	704,580	753,120
Accrued unbilled revenues	521,883	688,740
Inventories	562,721	618,232
Regulatory assets	353,807	402,235
Derivative instruments	79,988	64,340
Deferred income taxes	225,877	178,446
Prepayments and other	174,715	121,480
Total current assets	3,370,844	2,982,564
Property, plant and equipment, net	23,401,597	22,353,367
Other assets		
Nuclear decommissioning fund and other investments	1,578,381	1,463,515
Regulatory assets	2,367,431	2,389,008
Derivative instruments	135,739	152,887
Other	203,506	155,926
Total other assets	4,285,057	4,161,336
Total assets	$31,057,498	$29,497,267
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$859,462	$1,059,922
Short-term debt	304,000	219,000
Accounts payable	885,099	902,078
Regulatory liabilities	219,464	275,095
Taxes accrued	264,792	289,713
Accrued interest	160,621	177,111
Dividends payable	131,653	126,487
Derivative instruments	33,126	157,414
Other	302,317	381,819
Total current liabilities	3,160,534	3,588,639
Deferred credits and other liabilities		
Deferred income taxes	4,551,072	4,020,377
Deferred investment tax credits	83,971	86,743
Regulatory liabilities	1,053,542	1,101,534
Asset retirement obligations	1,716,612	1,651,793
Derivative instruments	248,321	263,906
Customer advances	252,879	248,345

Pension and employee benefit obligations	810,057	1,001,906
Other	224,400	203,313
Total deferred credits and other liabilities	8,940,854	8,577,917
Commitments and contingencies		
Capitalization		
Long-term debt	10,105,947	8,848,513
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 487,612,881 and 486,493,933 shares outstanding at Sept. 30, 2012 and Dec. 31, 2011, respectively	1,219,032	1,216,234
Additional paid in capital	5,334,715	5,327,443
Retained earnings	2,406,016	2,032,556
Accumulated other comprehensive loss	(109,600)	(94,035)
Total common stockholders' equity	8,850,163	8,482,198
Total liabilities and equity	$31,057,498	$29,497,267

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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 Sept. 30, 2012 and 2011						
Balance at June 30, 2011	484,543	$ 1,211,356	$ 5,261,687	$ 1,812,505	$ (50,983)	$ 8,234,565
Comprehensive income:						
Net income				338,332		338,332
Other comprehensive loss					(29,986)	(29,986)
Comprehensive income						308,346
Dividends declared:						
Cumulative preferred stock				(1,414)		(1,414)
Common stock				(126,723)		(126,723)
Premium on redemption of preferred stock				(3,260)		(3,260)
Issuances of common stock	405	1,013	8,738			9,751
Share-based compensation			10,038			10,038
Balance at Sept. 30, 2011	484,948	$ 1,212,369	$ 5,280,463	$ 2,019,440	$ (80,969)	$ 8,431,303
Balance at June 30, 2012	487,286	$ 1,218,214	$ 5,316,658	$ 2,140,639	$ (102,006)	$ 8,573,505
Comprehensive income:						
Net income				398,106		398,106
Other comprehensive loss					(7,594)	(7,594)
Comprehensive income						390,512
Dividends declared:						
Common stock				(132,729)		(132,729)
Issuances of common stock	327	818	8,679			9,497
Share-based compensation			9,378			9,378
Balance at Sept. 30, 2012	487,613	$ 1,219,032	$ 5,334,715	$ 2,406,016	$ (109,600)	$ 8,850,163

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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
Nine Months Ended Sept. 30, 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				700,663		700,663
Other comprehensive loss					(27,876)	(27,876)
Comprehensive income						672,787
Dividends declared:						
Cumulative preferred stock				(3,534)		(3,534)
Common stock				(376,132)		(376,132)
Premium on redemption of preferred stock				(3,260)		(3,260)
Issuances of common stock	2,614	6,535	18,462			24,997
Share-based compensation			32,926			32,926
Balance at Sept. 30, 2011	484,948	$1,212,369	$5,280,463	$2,019,440	$ (80,969)	$ 8,431,303
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				765,059		765,059
Other comprehensive loss					(15,565)	(15,565)
Comprehensive income						749,494
Dividends declared:						
Common stock				(391,599)		(391,599)
Issuances of common stock	1,819	4,548	19,449			23,997
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			27,909			27,909
Balance at Sept. 30, 2012	487,613	$1,219,032	$5,334,715	$2,406,016	$ (109,600)	$ 8,850,163

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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 Sept. 30, 2012 and Dec. 31, 2011; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and nine months ended Sept. 30, 2012 and 2011; and its cash flows for the nine months ended Sept. 30, 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 Sept. 30, 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 annual reporting 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)	Sept. 30, 2012	Dec. 31, 2011
Accounts receivable, net		
Accounts receivable	$753,782	$811,685
Less allowance for bad debts	(49,202)	(58,565)
	$704,580	$753,120

(Thousands of Dollars)	Sept. 30, 2012	Dec. 31, 2011
Inventories		
Materials and supplies	$213,949	$202,699
Fuel	202,872	236,023
Natural gas	145,900	179,510
	$562,721	$618,232

(Thousands of Dollars)	Sept. 30, 2012	Dec. 31, 2011
Property, plant and equipment, net		
Electric plant	$28,032,442	$27,254,541
Natural gas plant	3,774,764	3,676,754
Common and other property	1,476,663	1,546,643
Plant to be retired [(a)]	105,573	151,184
Construction work in progress	1,681,128	1,085,245
Total property, plant and equipment	35,070,570	33,714,367
Less accumulated depreciation	(12,023,296)	(11,658,351)
Nuclear fuel	2,075,442	1,939,299
Less accumulated amortization	(1,721,119)	(1,641,948)
	$23,401,597	$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 retired and in May 2012, Cherokee Unit 1 was retired. 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 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in September 2013. In the third quarter of 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011.

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 Sept. 30, 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	2008
Texas	2007
Wisconsin	2008

As of Sept. 30, 2012, there were no state income tax audits in progress.

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

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

(Millions of Dollars)	Sept. 30, 2012	Dec. 31, 2011
Unrecognized tax benefit — Permanent tax positions	$4.7	$4.3
Unrecognized tax benefit — Temporary tax positions	32.6	30.4
Total unrecognized tax benefit	$37.3	$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)	Sept. 30, 2012	Dec. 31, 2011
NOL and tax credit carryforwards	$(36.2)	$(33.6)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS audit progresses and state audits resume. At this time, due to the uncertain nature of the audit process, an overall range of possible change cannot be reasonably estimated.

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 Sept. 30, 2012 and Dec. 31, 2011 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 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 in the first quarter of 2012.

Impact of the Patient Protection and Affordable Care Act — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to the federal subsidies during the first quarter of 2010.

In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million of income tax benefit.

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

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.

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In November 2011, NSP-Minnesota reached a settlement agreement with certain customer intervenors. In February 2012, NSP-Minnesota filed to reduce the interim rate request to $72.8 million to align with the settlement agreement. In March 2012, the MPUC approved the settlement. In May 2012, the MPUC issued an order approving the following:

- 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.

NSP-Minnesota filed its final rate implementation and interim rate refund compliance filing in June 2012, which the MPUC approved in August 2012. Final rates were implemented Sept. 1, 2012, and interim refunds will be completed during October 2012.

NSP Minnesota – Minnesota Property Tax Deferral Request — In December 2011, NSP-Minnesota filed a request to defer incremental 2012 property taxes that would not be recovered in base rates, estimated to be approximately $24 million, or alternatively that a property tax rider be approved. In June 2012, the MPUC denied NSP-Minnesota's request for deferred accounting for incremental property taxes and also denied the request for a property tax rider. There were no incremental 2012 property taxes deferred as a regulatory asset.

Pending and Recently Concluded Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota 2011 Electric Rate Case — In June 2011, NSP-Minnesota filed a request with the SDPUC to increase electric rates by $14.6 million annually, effective in 2012. The request was 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. On Jan. 2, 2012, interim rates of $12.7 million were implemented. In June 2012, the SDPUC authorized a rate increase of approximately $8.0 million, based on an ROE of 9.25 percent, and an equity ratio of 53 percent. Final rates became effective Aug. 1, 2012. Interim rate refunds of $2.9 million were completed in September 2012.

NSP-Minnesota – South Dakota 2012 Electric Rate Case — In June 2012, NSP-Minnesota filed a request with the SDPUC to increase electric rates by $19.4 million annually. The request was based on a 2011 historic test year adjusted for known and measurable changes for 2012 and 2013, a requested ROE of 10.65 percent, an average rate base of $367.5 million and an equity ratio of 52.89 percent. Discovery is being conducted and a procedural schedule has not been established. A SDPUC decision is expected in late 2012 or early 2013.

NSP-Wisconsin

Pending Regulatory Proceedings — Public Service Commission of Wisconsin (PSCW)

NSP-Wisconsin – 2012 Electric and Gas Rate Case — In June 2012, NSP-Wisconsin filed a request with the PSCW to increase rates for electric and natural gas service effective Jan. 1, 2013. NSP-Wisconsin requested an overall increase in annual electric rates of $39.1 million, or 6.7 percent, and an increase in natural gas rates of $5.3 million, or 4.9 percent.

The electric rate filing was based on a 2013 forecast test year, an ROE of 10.40 percent, an equity ratio of 52.50 percent and an average 2013 electric rate base of approximately $788.6 million. The natural gas rate request was solely due to a proposal to recover the initial costs associated with the environmental cleanup of the Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) in Ashland, Wis.

On Oct. 19, 2012, the PSCW Staff and intervenors filed their direct testimony. The PSCW Staff recommended an electric rate increase of $32.9 million, or 5.6 percent, based on a 10.40 percent ROE and a 52.50 percent equity ratio. The major adjustments recommended by the PSCW Staff were a $2.2 million reduction in employee compensation expense primarily related to disallowance of the annual incentive program and a net $2.9 million reduction in electric fuel expense and fixed production charges. The PSCW Staff testimony acknowledged the unique issues before the PSCW related to the Ashland site cleanup and presented several alternatives for consideration by the PSCW.

Rebuttal testimony is expected to be filed on Oct. 31, 2012, and the hearing is expected to be held on Nov. 7, 2012. A PSCW decision is anticipated in December 2012.

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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.

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

- PSCo would implement an annual electric rate increase of $73 million in 2012. The rate increase was effective on May 1, 2012. 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.
- 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 will 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 signing parties agreed to implement an earnings test, in which customers and shareholders will share weather normalized 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 agreed that it will not file for an electric rate increase that would take effect prior to Jan. 1, 2015, provided that net revenue requirements increase or decrease 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 acknowledged 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.

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 March 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. PSCo has continued to credit the customer share of REC margins to the RESA regulatory asset balance each month. As of Sept. 30, 2012, PSCo has credited $41.2 million.

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.

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

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission formula rates from a historic test year formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. 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 wholesale transmission and ancillary services revenue by approximately $2.0 million annually. Various transmission customers taking service under the tariff protested the filing. In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to Nov. 17, 2012, subject to refund, and setting the case for settlement judge or hearing procedures. PSCo has been engaged in discovery and initial settlement discussions with the intervenors and the FERC Staff.

Separately, several wholesale customers filed a complaint with the FERC in June 2012 seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012. If implemented, the ROE reduction would reduce PSCo transmission and ancillary rate revenues by approximately $1.8 million annually. On Oct. 5, 2012, the FERC issued an order accepting the complaint, consolidating the complaint with the April 2012 formula rate change filing, establishing a refund effective date of July 1, 2012, and setting the complaint for settlement judge and hearing procedures. The settlement discussions are now expected to seek to resolve both dockets. If PSCo, the FERC and intervenors do not reach settlement, the dockets would proceed to a contested hearing.

SPS

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

SPS Wholesale Rate Complaint — In April 2012, Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a rate complaint with the FERC alleging that SPS' rates for wholesale service were excessive. Golden Spread alleges that the base ROE currently charged to them through the SPS production formula rate, of 10.25 percent, and the SPS transmission base formula rate, ROE of 10.77 percent, is unjust and unreasonable. Golden Spread alleges that the appropriate base ROE is 9.15 percent, or an annual difference of approximately $3.3 million. An additional 50 basis point incentive is added to the base ROE for the transmission formula rate for SPS' participation in the Southwest Power Pool, Inc. (SPP) Regional Transmission Organization (RTO). Golden Spread is not contesting this transmission incentive. The FERC has taken no action on this complaint.

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 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 3,324 megawatts (MW) and 3,773 MW of capacity under long term purchased power agreements as of Sept. 30, 2012 and Dec. 31, 2011, respectively, 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 Sept. 30, 2012 and Dec. 31, 2011, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

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

(Millions of Dollars)	Sept. 30, 2012	Dec. 31, 2011
Guarantees issued and outstanding	$68.4	$67.5
Current exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	30.0	31.2

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, at Sept. 30, 2012 and Dec. 31, 2011. The indemnification obligation expires in March 2013. NSP-Minnesota has not recorded a liability related to this indemnity at Sept. 30, 2012 or Dec. 31, 2011.

In connection with the acquisition of 900 MW of natural 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 at Sept. 30, 2012 or Dec. 31, 2011.

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

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 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 remediation at the site. The special notice letters requested that those PRPs participate in negotiations with the EPA regarding how the PRPs intended to conduct or pay for the remediation. As a result of those settlement negotiations, the EPA agreed to segment the Ashland site into separate areas. The first area (Phase I Project Area) includes soil and groundwater in Kreher Park and the Upper Bluff. The second area includes the Sediments.

In October 2012, a settlement among the EPA, the Wisconsin Department of Natural Resources (WDNR), the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin was approved by the U.S. District Court for the Western District of Wisconsin. This settlement resolves claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the settlement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. The settlement reflects a cost estimate for the clean up of the Phase I Project Area of $40 million. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. As part of the settlement, NSP-Wisconsin will convey approximately 1,390 acres of land to the State of Wisconsin and tribes so that they may manage and preserve the natural resource benefits associated with those properties. Assuming final access agreements are obtained, fieldwork at the Ashland site will commence as early as November 2012.

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Negotiations between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments are ongoing. The EPA's ROD for the Ashland site estimates that the cost of the preferred remediation related to the Sediments is between $63.3 million and $77.1 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. Answers to the NSP-Wisconsin complaint were due from other parties on Oct. 22, 2012. The U.S. District Court has not yet issued a scheduling order for litigation.

At each of Sept. 30, 2012 and Dec. 31, 2011, NSP-Wisconsin had recorded a liability of $104.3 million for the Ashland site 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 for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, the contributions, if any, by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred, as a regulatory asset, the estimated site remediation costs less insurance and rate recoveries, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin 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. Pursuant to the PSCW decision, NSP-Wisconsin proposed an alternative long-term plan to recover costs related to the Ashland site in the rate case application filed on June 1, 2012. As compared to the current cost recovery policy, NSP-Wisconsin's alternative proposal mitigates the rate impact to natural gas customers and allows for partial recovery of carrying costs. NSP-Wisconsin expects a decision on the alternative cost recovery plan by the end of 2012.

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 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 Sept. 30, 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.

Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard Proposal (NSPS) and Emission Guideline for Existing Sources — In April 2012, the EPA proposed a GHG NSPS for newly constructed power plants. The proposal requires that carbon dioxide (CO_2) 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 that installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. Xcel Energy submitted comments on the proposed GHG NSPS in June 2012. It is not possible to evaluate the impact of this regulation until its final requirements are known.

The EPA also plans to propose GHG regulations applicable to emissions from existing power plants under the Clean Air Act (CAA). It is not known when the EPA will propose new 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 CO_2 emissions from power plants and other industrial sources. The EIB repealed both regulations in the first quarter of 2012. Western Resource Advocates and New Energy Economy, Inc. have since filed appeals with the New Mexico Court of Appeals to challenge each of the EIB's decisions to repeal the two GHG rules.

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Cross-State Air Pollution Rule (CSAPR) — In July 2011, the EPA issued the CSAPR intended to address long range transport of particulate matter (PM) and ozone by requiring reductions in sulfur dioxide (SO_2) and nitrogen oxide (NOx) from utilities located in the eastern half of the United States. For Xcel Energy, the rule, if implemented, would have applied in Minnesota, Wisconsin and Texas. The CSAPR would have set more stringent requirements than the proposed Clean Air Transport Rule and specifically would have required plants in Texas to reduce their SO_2 and annual NOx emissions. The rule also would have created an emissions trading program.

In August 2012, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit also stated that the EPA must continue administering the Clean Air Interstate Rule (CAIR) pending adoption of a valid replacement. In October 2012, the EPA, as well as state and local governments and environmental advocates, petitioned the D.C. Circuit to rehear the CSAPR appeal. It is not yet known whether the court will grant rehearing of the case, or how the EPA might approach a replacement rule. Therefore, it is not known what requirements may be imposed in the future.

If the EPA continues administering the CAIR while the CSAPR is pending, Xcel Energy expects to comply with the CAIR primarily through the purchase of emissions allowances. Based on current CAIR allowance prices, the cost of CAIR compliance is not expected to have a material impact on results of operations, financial position or cash flows.

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 expects to comply with the EGU MATS rule through a combination of mercury and other emission control projects. 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 are subject to BART requirements. Individual states were required to identify the facilities located in their states that will have to reduce SO_2, NOx and PM emissions under BART and then set emissions limits for those facilities.

PSCo

In 2006, the Colorado Air Quality Control Commission (CAQCC) 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 CAQCC approved a revised regional haze BART state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. The Colorado legislature enacted a statute approving the SIP (the Colorado SIP), which was signed into law in 2011. Subsequently, the Colorado Mining Association (CMA) challenged the Colorado SIP in a Colorado District Court. In June 2012, the CMA's appeal was dismissed due to the legislative approval given to the Colorado SIP after the CAQCC approval. The CMA appealed this decision to the Colorado Court of Appeals in August 2012.

In September 2012, the EPA granted final approval of the Colorado SIP, including the CACJA emission reduction plan for PSCo, as satisfying BART requirements. The emission controls are expected to be installed between 2014 and 2017. Projected costs for emission controls at the Hayden and Pawnee plants are $334.2 million. PSCo expects the cost of any required capital investment will be recoverable from customers through the CACJA emission reduction plan recovery mechanisms or other regulatory mechanisms.

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.

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NSP-Minnesota

In December 2009, the Minnesota Pollution Control Agency (MPCA) approved the regional haze SIP for Minnesota (the Minnesota 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 SO_2. 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, regional haze 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 through regulatory recovery mechanisms.

In June 2011, the EPA provided comments to the MPCA on the Minnesota 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 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.

In April 2012, the MPCA approved a supplement to the 2009 regional haze Minnesota SIP finding that the 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 SO_2 by January 2015. In May 2012, the EPA adopted a final rule that allows states to determine whether CSAPR compliance meets BART requirements. In June 2012, the EPA issued its final approval of the Minnesota SIP for EGUs.

In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eight Circuit. NSP-Minnesota has petitioned to intervene in the case. It is not yet known how the D.C. Circuit's reversal of the CSAPR may impact the EPA's approval of the Minnesota SIP.

In addition to the regional haze rules identified in the EPA's visibility program, and addressed in the Minnesota 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. In May 2012, a notice of intent to sue was filed with the EPA by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club. The notice advised the EPA of the parties' intent to sue the EPA in 180 days to attempt to require the EPA to determine BART for the Sherco Units 1 and 2 under the RAVI program. It is not yet known how the EPA intends to respond to this notice.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a regional haze SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs, and as a result, no additional controls for these units beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. It is not yet known how the D.C. Circuit's reversal of the CSAPR may impact the EPA's approval of the Texas SIP.

Revisions to National Ambient Air Quality Standards (NAAQS) for PM — In June 2012, the EPA proposed to lower the primary (health-based) NAAQS for annual average fine PM and to retain the current daily standard for fine PM. In areas in which Xcel Energy operates power plants, current monitored air concentrations are below the range of the proposed annual primary standard. The EPA also proposed to add a secondary (welfare-based) NAAQS to improve visibility, primarily in urban areas. Xcel Energy expects the proposed visibility standard would likely be met where Xcel Energy operates power plants based on currently available information. A final rule is expected in December 2012 and the EPA is expected to designate non-compliant locations by December 2014. If such areas are identified, states would then study the sources of the nonattainment and make emission reduction plans to attain the standards. It is not possible to evaluate the impact of this regulation further until its final requirements are known.

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Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss, in certain situations, including but not limited to where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy's financial statements.

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 the 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 CO_2 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 (Ninth Circuit). In October 2012 the Ninth Circuit affirmed the U.S. District Court's dismissal. On Oct. 14, 2012, plaintiffs filed a petition for rehearing en banc. It is uncertain when the Ninth Circuit will respond to this petition. 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. Although Xcel Energy believes the likelihood of loss is remote based primarily on existing case law, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. 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 the U.S. District Court in Mississippi. The complaint alleges defendants' CO_2 emissions intensified the strength of Hurricane Katrina and increased the damage plaintiffs purportedly sustained to their property. Plaintiffs base their claims on public and private nuisance, trespass and negligence. Among the defendants named in the complaint are Xcel Energy Inc., SPS, PSCo, NSP-Wisconsin and NSP-Minnesota. The amount of damages claimed by plaintiffs is unknown. The defendants, including Xcel Energy Inc., believe this lawsuit is without merit and filed a motion to dismiss the lawsuit. In March 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. Although Xcel Energy believes the likelihood of loss is remote based primarily on existing case law, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. 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. 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 the 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, approximately $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit and filed a motion to dismiss. In September 2011, the U.S. District Court denied the motion to dismiss. On Oct. 22, 2012, NSP-Minnesota filed a motion for summary judgment. If the U.S. District Court denies NSP-Minnesota's motion, trial in this matter is expected to occur during the first or second quarter of 2013. Although Xcel Energy believes the likelihood of loss is remote based primarily on existing case law, it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. No accrual has been recorded for this matter.

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Exelon Wind (formerly John Deere Wind (JD Wind)) Complaint — Several lawsuits in Texas state and federal courts and regulatory proceedings have arisen out of a dispute concerning SPS' payments for energy produced from the Exelon Wind subsidiaries' projects. There are two main areas of dispute. First, Exelon Wind claims that it established legally enforceable obligations (LEOs) for each of its 12 wind facilities in 2005 through 2008 that require SPS to buy power based on SPS' forecasted avoided cost as determined in 2005 through 2007. Although SPS has refused to accept Exelon Wind's LEOs, SPS has paid Exelon Wind for energy under SPS' Public Utility Commission of Texas (PUCT) Qualifying Facilities (QF) Tariff. Second, Exelon Wind has raised various challenges to SPS' PUCT QF Tariff, which became effective in August 2010. The state and federal lawsuits are in various stages of litigation. SPS believes the likelihood of loss in these lawsuits is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

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

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

The FERC has issued an order on remand establishing principles for the review proceeding in October 2011. In September 2012, the City of Seattle filed its direct case against PSCo and other Pacific Northwest sellers and has expanded the period for which it seeks refunds to May 2000 through June 2001, during which PSCo had sales to the City of Seattle of approximately $50 million. The City of Seattle did not identify specific instances of unlawful market activity by PSCo, but rather based its claim for refunds on market dysfunction in the Western markets. Preliminary calculations of the City of Seattle's claim for refunds from PSCo are approximately $28 million not including interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors: PSCo's view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and that the FERC's standard will likely be challenged on appeal to the U.S. Court of Appeals for the Ninth Circuit. PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. In addition, if a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Nuclear Power Operations and Waste Disposal

Nuclear Waste Disposal Litigation — In 1998, NSP Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy's (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the United States and

NSP Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the court awarded NSP Minnesota $116.5 million in damages. In August 2007, NSP Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008.

In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, estimated to be an additional $100 million. The settlement does not address costs for used fuel storage after 2013; such costs could be the subject of future litigation. NSP-Minnesota received the initial $100 million payment in August 2011 and the second installment of $18.6 million in March 2012, which were subsequently refunded to customers, except for approved reductions such as legal costs and customer refund amounts still in process at Sept. 30, 2012. Also pursuant to this settlement agreement, on Aug. 8, 2012, the DOE approved reimbursement in the amount of approximately $20.7 million for costs incurred in 2011 for storing spent nuclear fuel. NSP-Minnesota recognized the expected payment of $20.7 million as a receivable as of Sept. 30, 2012, which was subsequently received in October 2012. NSP-Minnesota and NSP-Wisconsin expect to make the appropriate regulatory filings within the prescribed deadlines for the various jurisdictions.

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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:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Sept. 30, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	304	219
Average amount outstanding	433	430
Maximum amount outstanding	630	824
Weighted average interest rate, computed on a daily basis	0.34%	0.36%
Weighted average interest rate at period end	0.34	0.40

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 Sept. 30, 2012 and Dec. 31, 2011, there were $12.7 million of letters of credit outstanding under the credit facilities. There were no letters of credit outstanding that were not issued under the credit facilities at Sept. 30, 2012. There were $1.1 million of letters of credit outstanding at Dec. 31, 2011 that were not issued under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

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 facilities. 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 Sept. 30, 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	$ 205.0	$ 595.0
PSCo	700.0	4.0	696.0
NSP-Minnesota	500.0	8.7	491.3
SPS	300.0	-	300.0
NSP-Wisconsin	150.0	99.0	51.0
Total	$ 2,450.0	$ 316.7	$ 2,133.3

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Sept. 30, 2012 and Dec. 31, 2011.

Amended Credit Agreements — In July 2012, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. entered into amended five-year credit agreements with a syndicate of banks, replacing their previous four-year credit agreements. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an improvement in pricing and an extension of maturity from March 2015 to July 2017. The Eurodollar borrowing margins on these lines of credit were reduced from a range of 100 to 200 basis points per year, to a range of 87.5 to 175 basis points per year based on applicable long-term credit ratings. The commitment fees, calculated on the unused portion of the lines of credit, were reduced from a range of 10 to 35 basis points per year, to a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

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Xcel Energy Inc. and its utility subsidiaries, other than NSP-Wisconsin, have the right to request an extension of the revolving termination date for two additional one-year periods, and NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period, each subject to majority bank group approval.

Long-Term Borrowings and Other Financing Instruments

SPS — In June 2012, SPS issued an additional $100 million of its 4.50 percent first mortgage bonds due Aug. 15, 2041. Including the $200 million of this series previously issued in August 2011, total principal outstanding for this series is $300 million.

NSP-Minnesota — In August 2012, NSP-Minnesota issued $300 million of 2.15 percent first mortgage bonds due Aug. 15, 2022, as well as $500 million of 3.40 percent first mortgage bonds due Aug. 15, 2042. NSP-Minnesota used a portion of the net proceeds from the first mortgage bonds to repay $450 million of 8.0 percent first mortgage bonds maturing on Aug. 28, 2012 and to redeem the following series of pollution control bonds: $100 million of 8.50 percent bonds due Sept. 1, 2019, $27.9 million of 8.50 percent bonds due March 1, 2019 and $69 million of 8.50 percent bonds due April 1, 2030.

PSCo — In September 2012, PSCo issued $300 million of 2.25 percent first mortgage bonds due Sept. 15, 2022, as well as $500 million of 3.60 percent first mortgage bonds due Sept. 15, 2042. PSCo used a portion of the net proceeds from the first mortgage bonds to redeem $600 million of 7.875 percent first mortgage bonds maturing on Oct. 1, 2012, and intends to redeem $48.75 million of 5.10 percent bonds due Jan. 1, 2019, for which a notice of full optional redemption was issued to bondholders on Oct. 1, 2012.

NSP-Wisconsin — In October 2012, NSP-Wisconsin issued $100 million of 3.70 percent first mortgage bonds due Oct. 1, 2042.

Preferred Stock — Xcel Energy Inc. has authorized 7,000,000 shares of preferred stock with a $100 par value. At Sept. 30, 2012 and Dec. 31, 2011, there were no shares of preferred stock outstanding.

In 2011, Xcel Energy Inc. redeemed all series of its preferred stock at an aggregate purchase price of $108 million, plus accrued dividends. The redemption premium of $3.3 million and accrued dividends are reflected as reductions of Xcel Energy's earnings available to common shareholders in the consolidated statements of income for the three and nine months ended Sept. 30, 2011.

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 hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with discounted cash flow or option pricing models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

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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 with proper notice. 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 Xcel Energy'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 energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, 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.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, 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 unsettled commodity derivatives presented in the consolidated balance sheets.

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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 nuclear decommissioning fund were $146.3 million and $79.8 million at Sept. 30, 2012 and Dec. 31, 2011, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $49.4 million and $87.5 million at Sept. 30, 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 Sept. 30, 2012 and Dec. 31, 2011:

	Sept. 30, 2012				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$28,835	$16,074	$12,761	$-	$28,835
Commingled funds	375,958	-	398,592	-	398,592
International equity funds	65,713	-	66,518	-	66,518
Private equity investments	20,662	-	-	24,073	24,073
Real estate	30,252	-	-	35,233	35,233
Debt securities:					
Government securities	126,381	-	127,124	-	127,124
U.S. corporate bonds	153,283	-	164,501	-	164,501
International corporate bonds	24,952	-	26,442	-	26,442
Municipal bonds	61,683	-	66,800	-	66,800
Asset-backed securities	4,971	-	-	4,995	4,995
Mortgage-backed securities	60,628	-	-	63,957	63,957
Equity securities:					
Common stock	402,769	445,891	-	-	445,891
Total	$1,356,087	$461,965	$862,738	$128,258	$1,452,961

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $91.4 million of equity investments in unconsolidated subsidiaries and $34.0 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 for the three and nine months ended Sept. 30, 2012 and 2011:

(Thousands of Dollars)	July 1, 2012	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Sept. 30, 2012
Private equity investments	$23,303	$ -	$ (1,931)	$ 2,701	$24,073
Real estate	32,721	2,882	(1,165)	795	35,233
Asset-backed securities	7,068	-	(2,085)	12	4,995
Mortgage-backed securities	66,321	16,782	(19,681)	535	63,957
Total	$129,413	$ 19,664	$ (24,862)	$ 4,043	$128,258

(Thousands of Dollars)	July 1, 2011	Purchases	Settlements	Losses Recognized as Regulatory Assets	Sept. 30, 2011
Asset-backed securities	$21,004	$ 9,496	$ (19,443)	$ (811)	$10,246
Mortgage-backed securities	62,271	1,972	(8,978)	(450)	54,815
Total	$83,275	$ 11,468	$ (28,421)	$ (1,261)	$65,061

Purchases Settlements

(Thousands of Dollars)	Jan. 1, 2012			Gains Recognized as Regulatory Liabilities	Sept. 30, 2012
Private equity investments	$9,203	$ 13,390	$ (1,931)	$ 3,411	$24,073
Real estate	26,395	6,789	(2,931)	4,980	35,233
Asset-backed securities	16,501	-	(11,544)	38	4,995
Mortgage-backed securities	78,664	31,100	(46,099)	292	63,957
Total	$130,763	$ 51,279	$ (62,505)	$ 8,721	$128,258

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(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Losses Recognized as Regulatory Assets	Sept. 30, 2011
Asset-backed securities	$ 33,174	$ 10,252	$ (32,559)	$ (621)	$ 10,246
Mortgage-backed securities	72,589	101,037	(117,435)	(1,376)	54,815
Total	$ 105,763	$ 111,289	$ (149,994)	$ (1,997)	$ 65,061

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at Sept. 30, 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	$ 104,587	$ 7,074	$ 1,848	$ 13,615	$ 127,124
U.S. corporate bonds	-	37,372	111,801	15,328	164,501
International corporate bonds	-	8,108	16,657	1,677	26,442
Municipal bonds	-	-	31,417	35,383	66,800
Asset-backed securities	-	4,237	758	-	4,995
Mortgage-backed securities	-	-	824	63,133	63,957
Debt securities	$ 104,587	$ 56,791	$ 163,305	$ 129,136	$ 453,819

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.

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 Sept. 30, 2012, accumulated other comprehensive losses related to interest rate derivatives included $2.7 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

In conjunction with the NSP-Minnesota debt issuance in August 2012, NSP-Minnesota settled interest rate hedging instruments with a notional amount of $225 million during the three months ended Sept. 30, 2012 with cash payments of $45.0 million. In conjunction with the PSCo debt issuance in September 2012, PSCo settled interest rate hedging instruments with a notional amount of $250 million during the three months ended Sept. 30, 2012 with cash payments of $44.7 million. These losses are classified as a component of accumulated other comprehensive loss on the consolidated balance sheet, net of tax, and will be reclassified to earnings over the term of the hedged interest payments. See Note 7 for further discussion of long-term borrowings.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various 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, natural gas for resale and vehicle fuel.

At Sept. 30, 2012, Xcel Energy had various vehicle fuel related contracts designated as cash flow hedges extending through December 2016. 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 and nine months ended Sept. 30, 2012 and 2011.

At Sept. 30, 2012, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

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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 Sept. 30, 2012 and Dec. 31, 2011:

(Amounts in Thousands) [a][b]	Sept. 30, 2012	Dec. 31, 2011
Megawatt hours (MWh) of electricity	54,374	38,822
MMBtu of natural gas	8,238	40,736
Gallons of vehicle fuel	732	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.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated other comprehensive loss, included in the consolidated statement of common stockholders' equity and in the consolidated statement of comprehensive income, is detailed in the following table:

(Thousands of Dollars)	Three Months Ended Sept. 30 2012	2011
Accumulated other comprehensive loss related to cash flow hedges at July 1	$(55,710)	$(7,582)
After-tax net unrealized losses related to derivatives accounted for as hedges	(8,853)	(30,947)
After-tax net realized losses on derivative transactions reclassified into earnings	393	159
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$(64,170)	$(38,370)

(Thousands of Dollars)	Nine Months Ended Sept. 30 2012	2011
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(45,738)	$(8,094)
After-tax net unrealized losses related to derivatives accounted for as hedges	(19,188)	(30,740)
After-tax net realized losses on derivative transactions reclassified into earnings	756	464
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$(64,170)	$(38,370)

The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2012 and Sept. 30, 2011, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

Three Months Ended Sept. 30, 2012		
Fair Value Gains (Losses) Recognized During the Period in:	Pre-Tax (Gains) Losses Reclassified into Income During the Period from:	
Accumulated	Accumulated	Pre-Tax Gains

(Thousands of Dollars)	Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$(14,923)	$-	$733 (a)	$-	$-
Vehicle fuel and other commodity	157	-	(44) (e)	-	-
Total	$(14,766)	$-	$689	$-	$-
Other derivative instruments					
Trading commodity	$-	$-	$-	$-	$7,651 (b)
Electric commodity	-	3,923	-	(11,931) (c)	-
Natural gas commodity	-	1,193	-	-	-
Total	$-	$5,116	$-	$(11,931)	$7,651

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	Nine Months Ended Sept. 30, 2012				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses 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	$ (31,914)	$ -	$ 1,511 (a)	$ -	$ -
Vehicle fuel and other commodity	140	-	(145) (e)	-	-
Total	$ (31,774)	$ -	$ 1,366	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 10,963 (b)
Electric commodity	-	43,679	-	(29,616) (c)	-
Natural gas commodity	-	(8,705)	-	80,939 (d)	(109) (c)
Total	$ -	$ 34,974	$ -	$ 51,323	$ 10,854

	Three Months Ended Sept. 30, 2011				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses 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	$ (51,033)	$ -	$ 354 (a)	$ -	$ -
Vehicle fuel and other commodity	(206)	-	(45) (e)	-	-
Total	$ (51,239)	$ -	$ 309	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 326 (b)
Electric commodity	-	10,392	-	(11,050) (c)	-
Natural gas commodity	-	(41,120)	-	308 (d)	(126) (c)
Total	$ -	$ (30,728)	$ -	$ (10,742)	$ 200

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	Nine Months Ended Sept. 30, 2011				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses 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	$(51,033)	$ -	$1,031 (a)	$ -	$ -
Vehicle fuel and other commodity	105	-	(129) (e)	-	-
Total	$(50,928)	$ -	$902	$ -	$ -
Other derivative instruments					
Trading commodity	$-	$ -	$-	$ -	$ 7,096 (b)
Electric commodity	-	29,537	-	(28,605) (c)	-
Natural gas commodity	-	(58,299)	-	58,433 (d)	(126) (c)
Total	$-	$ (28,762)	$-	$ 29,828	$ 6,970

(a) Amounts are recorded to interest charges.

(b) Amounts are 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) Amounts are 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) Amounts for the nine months ended Sept. 30, 2012 and 2011 include $5.0 million and $9.9 million of settlement losses, respectively, on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. The remaining settlement losses for the nine months ended Sept. 30, 2012 and 2011, and all settlement losses for the three months ended Sept. 30, 2012 and 2011, relate to natural gas operations and are recorded to cost of natural gas sold and transported. These losses are subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate.

(e) Amounts are recorded to operating and maintenance (O&M) expenses.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2012 and Sept. 30, 2011. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale (NPNS) contracts and therefore not reflected on the balance sheet, 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, derivative instruments reflected in a $17.7 million and $8.3 million gross liability position on the consolidated balance sheets at Sept. 30, 2012 and Dec. 31, 2011, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle outstanding contracts, including NPNS contracts, which would have resulted in payments of $5.4 million and $9.3 million at Sept. 30, 2012 and Dec. 31, 2011, respectively, inclusive of the impacts of the offsetting asset positions with the applicable counterparties. At Sept. 30, 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 Sept. 30, 2012 and Dec. 31, 2011.

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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 Sept. 30, 2012:

	Sept. 30, 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:						
Vehicle fuel and other commodity	$-	$134	$-	$134	$ -	$134
Other derivative instruments:						
Trading commodity	5	27,259	-	27,264	(7,962)	19,302
Electric commodity	-	-	27,583	27,583	(1,801)	25,782
Natural gas commodity	-	2,080	-	2,080	(28)	2,052
Total current derivative assets	$5	$29,473	$27,583	$57,061	$ (9,791)	47,270
Purchased power agreements (a)						32,718
Current derivative instruments						$79,988
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$137	$-	$137	$ (76)	$61
Other derivative instruments:						
Trading commodity	-	43,485	-	43,485	(5,050)	38,435
Total noncurrent derivative assets	$-	$43,622	$-	$43,622	$ (5,126)	38,496
Purchased power agreements (a)						97,243
Noncurrent derivative instruments						$135,739

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(Thousands of Dollars)	Sept. 30, 2012 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative liabilities						
Other derivative instruments:						
Trading commodity	$109	$20,683	$-	$20,792	$ (10,547)	$10,245
Electric commodity	-	-	1,801	1,801	(1,801)	-
Natural gas commodity	-	2	-	2	(2)	-
Total current derivative liabilities	$109	$20,685	$1,801	$22,595	$ (12,350)	10,245
Purchased power agreements [a]						22,881
Current derivative instruments						$33,126
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$22,067	$-	$22,067	$ (5,125)	$16,942
Total noncurrent derivative liabilities	$-	$22,067	$-	$22,067	$ (5,125)	16,942
Purchased power agreements [a]						231,379
Noncurrent derivative instruments						$248,321

(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:

(Thousands of Dollars)	Dec. 31, 2011 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$169	$-	$169	$ (76)	$93
Other derivative instruments:						
Trading commodity	-	32,682	-	32,682	(13,391)	19,291
Electric commodity	-	-	13,333	13,333	(1,471)	11,862

Total current derivative assets	$-	$32,851	$13,333	$46,184	$ (14,938)	31,246
Purchased power agreements [a]						33,094
Current derivative instruments						$64,340
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$107	$-	$107	$ (59)	$48
Other derivative instruments:						
Trading commodity	-	36,599	-	36,599	(5,540)	31,059
Total noncurrent derivative assets	$-	$36,706	$-	$36,706	$ (5,599)	31,107
Purchased power agreements [a]						121,780
Noncurrent derivative instruments						$152,887

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	Dec. 31, 2011 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	$-	$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 tables present the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2012 and 2011:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2012	2011
Balance at July 1	$33,789	$3,996
Settlements	(12,649)	(9,707)
Net transactions recorded during the period:		
Gains (losses) recognized in earnings [a]	13	(7)
Gains recorded as regulatory liabilities	4,629	9,037
Balance at Sept. 30	$25,782	$3,319

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2012	2011
Balance at Jan. 1	$12,417	$2,392
Purchases	37,296	33,609
Settlements	(34,209)	(25,708)
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	5	64
Gains (losses) recorded as regulatory assets and liabilities	10,273	(7,038)
Balance at Sept. 30	$25,782	$3,319

(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 and nine months ended Sept. 30, 2012 and 2011.

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Fair Value of Long-Term Debt

As of Sept. 30, 2012 and Dec. 31, 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

(Thousands of Dollars)	Sept. 30, 2012 Carrying Amount	Fair Value	Dec. 31, 2011 Carrying Amount	Fair Value
Long-term debt, including current portion	$10,965,409	$12,925,418	$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 Sept. 30, 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 Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	2012	2011	2012	2011
Interest income	$1,820	$1,974	$8,323	$8,228
Other nonoperating income	714	806	2,793	2,590
Insurance policy expense	(2,042)	(159)	(5,902)	(2,245)
Other nonoperating expense	(4)	(71)	(261)	(278)
Other income, net	$488	$2,550	$4,953	$8,295

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 $91.4 million and $92.7 million as of Sept. 30, 2012 and Dec. 31, 2011, respectively, included in the regulated natural gas utility 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 Sept. 30, 2012					
Operating revenues from external customers	$2,532,709	$174,513	$17,119	$ -	$2,724,341
Intersegment revenues	287	461	-	(748)	-
Total revenues	$2,532,996	$174,974	$17,119	$ (748)	$2,724,341
Income (loss) from continuing operations	$400,185	$4,296	$(6,334)	$ -	$398,147

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2011					
Operating revenues from external customers	$2,619,424	$194,930	$17,244	$ -	$2,831,598
Intersegment revenues	294	294	-	(588)	-
Total revenues	$2,619,718	$195,224	$17,244	$ (588)	$2,831,598
Income (loss) from continuing operations	$353,846	$(6,445)	$(9,106)	$ -	$338,295

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2012					
Operating revenues from external customers	$6,506,320	$1,016,861	$53,907	$ -	$7,577,088
Intersegment revenues	886	1,179	-	(2,065)	-
Total revenues	$6,507,206	$1,018,040	$53,907	$ (2,065)	$7,577,088
Income (loss) from continuing operations	$733,557	$60,688	$(29,254)	$ -	$764,991

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2011					
Operating revenues from external customers	$6,777,793	$1,251,817	$56,750	$ -	$8,086,360
Intersegment revenues	989	1,690	-	(2,679)	-
Total revenues	$6,778,782	$1,253,507	$56,750	$ (2,679)	$8,086,360
Income (loss) from continuing operations	$670,965	$58,748	$(29,280)	$ -	$700,433

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.

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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.

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

	Three Months Ended Sept. 30, 2012			Three Months Ended Sept. 30, 2011		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$398,106			$338,332		
Less: Dividend requirements on preferred stock	-			(1,414)		
Less: Premium on redemption of preferred stock	-			(3,260)		
Basic earnings per share:						
Earnings available to common shareholders	398,106	488,084	$ 0.82	333,658	485,344	$ 0.69
Effect of dilutive securities:						
401(k) equity awards	-	494		-	550	
Diluted earnings per share:						
Earnings available to common shareholders	$398,106	488,578	$ 0.81	$333,658	485,894	$ 0.69

	Nine Months Ended Sept. 30, 2012			Nine Months Ended Sept. 30, 2011		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$765,059			$700,663		
Less: Dividend requirements on preferred stock	-			(3,534)		
Less: Premium on redemption of preferred stock	-			(3,260)		
Basic earnings per share:						
Earnings available to common shareholders	765,059	487,722	$ 1.57	693,869	484,640	$ 1.43
Effect of dilutive securities:						
401(k) equity awards	-	476		-	512	
Diluted earnings per share:						
Earnings available to common shareholders	$765,059	488,198	$ 1.57	$693,869	485,152	$ 1.43

For the three and nine months ended Sept. 30, 2011, Xcel Energy Inc. had approximately 2.0 million and 2.3 million weighted average stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the EPS calculation. No stock options were outstanding during the three and nine month period ended Sept. 30, 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.

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12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended Sept. 30			
	2012	2011	2012	2011
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$21,591	$19,330	$1,050	$1,206
Interest cost	39,043	40,353	9,465	10,522
Expected return on plan assets	(51,774)	(55,400)	(7,102)	(7,991)
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	26,893	19,627	4,228	3,324
Net periodic benefit cost	41,019	29,543	9,333	9,439
Cost not recognized and additional cost recognized due to the effects of regulation	(9,645)	(9,299)	972	972
Net benefit cost recognized for financial reporting	$31,374	$20,244	$10,305	$10,411

	Nine Months Ended Sept. 30			
	2012	2011	2012	2011
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$64,773	$57,990	$3,152	$3,618
Interest cost	117,131	121,059	28,396	31,565
Expected return on plan assets	(155,322)	(166,200)	(21,307)	(23,972)
Amortization of transition obligation	-	-	10,740	10,833
Amortization of prior service cost (credit)	15,799	16,899	(5,664)	(3,699)
Amortization of net loss	80,678	58,883	12,680	9,971
Net periodic benefit cost	123,059	88,631	27,997	28,316
Cost not recognized and additional cost recognized due to the effects of regulation	(28,936)	(27,899)	2,918	2,918
Net benefit cost recognized for financial reporting	$94,123	$60,732	$30,915	$31,234

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.

In June 2012, to manage volatility in equity pricing within the pension master trust, Xcel Energy entered into equity collar contracts with a net-zero cost at initiation on a portion of the equity securities. The equity collar strategy is designed to reduce potential equity losses while limiting gains, resulting in lower equity volatility for the pension plans. At Sept. 30, 2012, the mark-to-market value of these arrangements was not material to the value of the pension trust assets or the consolidated results of operations, cash flows or financial position. These arrangements will expire in December 2012.

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 operating results, quarterly financial results are not an appropriate base from which to project annual results.

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward looking statements that are subject to certain risks, uncertainties and assumptions. Such forward looking statements, including the 2012 and 2013 full year earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. 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 Sept. 30, 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.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2012	2011	2012	2011
PSCo	$0.36	$0.29	$0.75	$0.63
NSP-Minnesota	0.28	0.29	0.57	0.62
SPS	0.12	0.10	0.20	0.17

NSP-Wisconsin	0.04	0.04	0.09	0.09
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility — continuing operations	0.81	0.73	1.64	1.54
Xcel Energy Inc. and other costs	(0.03)	(0.04)	(0.10)	(0.11)
Ongoing diluted earnings per share	0.78	0.69	1.54	1.43
Prescription drug tax benefit	0.03	-	0.03	-
GAAP diluted earnings per share	$0.81	$0.69	$1.57	$1.43

Ongoing earnings exclude adjustments for certain items. For 2012, these adjustments are related to the Patient Protection and Affordable Care Act. See below under Adjustments to GAAP Earnings and Note 4 for further discussion.

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

Adjustments to GAAP Earnings

Impact of the Patient Protection and Affordable Care Act — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to the federal subsidies during the first quarter of 2010.

In the third quarter of 2012, Xcel Energy implemented a tax strategy related to the allocation of funding of Xcel Energy's retiree prescription drug plan. This strategy restored a portion of the tax benefit associated with federal subsidies for prescription drug plans that had been accrued since 2004 and was expensed in 2010. As a result, Xcel Energy recognized approximately $17 million of income tax benefit.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Xcel Energy — Overall, ongoing earnings increased $0.09 per share for the third quarter and $0.11 per share for the nine months ended Sept. 30, 2012. Third quarter 2012 ongoing earnings increased largely due to increased electric and gas margins driven by various rate increases that went into effect in 2012, partially offset by increased property taxes and interest expense.

PSCo — PSCo's ongoing earnings increased $0.07 per share during the third quarter of 2012 and $0.12 per share for the nine months ended Sept. 30, 2012. The increases are primarily due to an electric rate increase, effective in May 2012, lower O&M expenses and the impact of warmer summer weather. The increases were partially offset by decreased wholesale revenue due to the expiration of a long-term wholesale power sales agreement with Black Hills Corp.

NSP-Minnesota — NSP-Minnesota's ongoing earnings decreased $0.01 per share for the third quarter of 2012 and $0.05 per share for the nine months ended Sept. 30, 2012. The ongoing earnings decline in the third quarter is primarily the result of cooler weather than in 2011, higher property taxes following the MPUC's denial of NSP-Minnesota's deferred accounting request and higher O&M expenses, which were partially offset by lower depreciation expense.

Year-to-date ongoing earnings decreased primarily due to the unfavorable impact of warmer than normal winter weather, higher property taxes, and higher O&M expenses. These decreases were partially offset by lower depreciation expense and a lower effective tax rate.

SPS — SPS' ongoing earnings increased $0.02 per share for the third quarter of 2012 and $0.03 per share for the nine months ended Sept. 30, 2012. The increases are the result of rate increases in New Mexico and Texas, effective January 2012, partially offset by the impact of milder weather during the third quarter, higher depreciation expense and higher property taxes.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings were flat for the third quarter of 2012 and for the nine months ended Sept. 30, 2012. Year-to-date ongoing earnings were positively impacted by rate increases, effective in January 2012, and the impact of warmer summer weather, offset by warmer winter weather.

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Changes in Diluted EPS

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

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2011 GAAP and ongoing diluted earnings per share	$ 0.69	$ 1.43
Components of change — 2012 vs. 2011		
Higher electric margins	0.07	0.09
Higher natural gas margins	0.02	-
Higher AFUDC - Equity	0.01	0.01
Higher interest charges	(0.01)	(0.02)
Higher taxes (other than income taxes)	(0.01)	(0.04)
Lower conservation and DSM expenses (generally offset in revenues)	-	0.03
Lower effective tax rate	-	0.03
Other, net (including interest and premium on redemption of preferred stock)	0.01	0.01
2012 ongoing diluted earnings per share	0.78	1.54
Prescription drug tax benefit	0.03	0.03
2012 GAAP diluted earnings per share	$ 0.81	$ 1.57

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

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Contributions to Income (Millions of Dollars)	2012	2011	2012	2011
Regulated electric income	$400.2	$353.8	$733.6	$671.0
Regulated natural gas income	4.3	(6.4)	60.7	58.7
All other (a)	8.8	8.4	20.0	18.1
Xcel Energy Inc. and other costs [(a)]	(15.2)	(17.5)	(49.3)	(47.3)
Total income — continuing operations	398.1	338.3	765.0	700.5
Income from discontinued operations	-	-	0.1	0.2
Total net income	$398.1	$338.3	$765.1	$700.7

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Contributions to Diluted Earnings (Loss) Per Share	2012	2011	2012	2011
Regulated electric	$0.82	$0.73	$1.50	$1.38
Regulated natural gas	0.01	(0.01)	0.13	0.12
All other (a)	0.01	0.01	0.04	0.04
Xcel Energy Inc. and other costs [(a)]	(0.03)	(0.04)	(0.10)	(0.11)
Total earnings per share — continuing operations	0.81	0.69	1.57	1.43
Discontinued operations	-	-	-	-
Total earnings per share — diluted	$0.81	$0.69	$1.57	$1.43

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

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Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Regulated Earnings — 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, from both an energy and demand perspective.

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

Normal weather conditions are defined as either the 20 year or 30 year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
HDD	(23.3) %	(11.9) %	(13.0) %	(21.4) %	3.8 %	(23.9) %
CDD	33.1	38.6	(4.2)	46.9	37.2	7.0
THI	34.3	50.4	(8.9)	37.2	36.0	2.4

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

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
Retail electric	$0.076	$0.075	$0.001	$0.083	$0.086	$(0.003)
Firm natural gas	(0.001)	0.000	(0.001)	(0.030)	0.008	(0.038)
Total	$0.075	$0.075	$0.000	$0.053	$0.094	$(0.041)

In 2012, Xcel Energy refined its estimate to incorporate the impact of weather on demand charges. As a result, the estimated weather impact on EPS for prior periods has been adjusted for comparison purposes.

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

	Three Months Ended Sept. 30	
	Actual	Weather Normalized
Electric residential	(1.2) %	(0.1) %
Electric commercial and industrial	(0.9)	(0.7)
Total retail electric sales	(1.0)	(0.6)
Firm natural gas sales	(1.3)	0.3

	Nine Months Ended Sept. 30		Nine Months Ended Sept. 30 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(1.4) %	(0.1) %	(1.8) %	(0.5) %
Electric commercial and industrial	0.2	0.1	(0.1)	(0.2)
Total retail electric sales	(0.3)	0.0	(0.6)	(0.3)
Firm natural gas sales	(15.8)	0.0	(16.4)	(0.8)

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 Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2012	2011	2012	2011
Electric revenues	$2,533	$2,619	$6,506	$6,778
Electric fuel and purchased power	(1,007)	(1,150)	(2,725)	(3,071)
Electric margin	$1,526	$1,469	$3,781	$3,707

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

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2012 vs. 2011	Nine Months Ended Sept. 30 2012 vs. 2011
Fuel and purchased power cost recovery	$ (146)	$ (341)
Firm wholesale [(a)]	(16)	(44)

Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, North Dakota, Michigan and Minnesota) [b]	46	76
Transmission revenue	16	38
Conservation and DSM incentive	13	18
Conservation and DSM revenue (offset by expenses)	-	(7)
Estimated impact of weather	-	(3)
Other, net	1	(9)
Total decrease in electric revenues	$ (86)	$ (272)

(a) Decrease is primarily due to the expiration of a long-term wholesale power sales agreement with Black Hills Corp. effective Jan. 1, 2012.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the third quarter of 2012 and $24 million for the nine months ended Sept. 30, 2012 to reflect the settlements in the 2011 Minnesota and South Dakota electric rate cases.

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Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2012 vs. 2011	Nine Months Ended Sept. 30 2012 vs. 2011
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, North Dakota, Michigan and Minnesota) [(a)]	$ 46	$ 76
Conservation and DSM incentive	13	18
Transmission revenue, net of costs	11	20
Firm wholesale [(b)]	(13)	(36)
Conservation and DSM revenue (offset by expenses)	-	(7)
Estimated impact of weather	-	(3)
Other, net	-	6
Total increase in electric margin	$ 57	$ 74

(a) NSP-Minnesota reduced depreciation expense and revenues by approximately $8 million in the third quarter of 2012 and $24 million for the nine months ended Sept. 30, 2012 to reflect the settlements in the 2011 Minnesota and South Dakota electric rate cases.

(b) Decrease is primarily due to the expiration of a long-term wholesale power sales agreement with Black Hills Corp. effective Jan. 1, 2012.

Natural Gas Revenues and Margin

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

(Millions of Dollars)	Three Months Ended Sept. 30 2012	2011	Nine Months Ended Sept. 30 2012	2011
Natural gas revenues	$175	$195	$1,017	$1,252
Cost of natural gas sold and transported	(50)	(87)	(557)	(794)
Natural gas margin	$125	$108	$460	$458

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 Sept. 30	Nine Months Ended Sept. 30

	2012 vs. 2011	2012 vs. 2011
Purchased natural gas adjustment clause recovery	$ (38)	$ (235)
Conservation and DSM revenue (offset by expenses)	(1)	(13)
Pipeline system integrity adjustment rider (Colorado), offset by expense	11	22
Retail rate increase (Colorado, Wisconsin)	7	16
Return on gas in storage	2	6
Estimated impact of weather	-	(28)
Other, net	(1)	(3)
Total decrease in natural gas revenues	$ (20)	$ (235)

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Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2012 vs. 2011	Nine Months Ended Sept. 30 2012 vs. 2011
Pipeline system integrity adjustment rider (Colorado), offset by expense	$ 11	$ 22
Retail rate increase (Colorado, Wisconsin)	7	16
Return on gas in storage	2	6
Conservation and DSM revenue (offset by expenses)	(1)	(13)
Estimated impact of weather	-	(28)
Other, net	(2)	(1)
Total increase in natural gas margin	$ 17	$ 2

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $1.5 million, or 0.3 percent, for the third quarter of 2012 and increased $1.0 million, or 0.1 percent, for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The changes are primarily attributable to management cost savings initiatives, partially offset by higher employee benefit expense.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses decreased $2.4 million, or 3.3 percent, for the third quarter of 2012 and $20.8 million, or 9.8 percent, for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The lower expenses are primarily attributable to lower gas rider rates, as well as the timing of recovery of 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.

Depreciation and Amortization — Depreciation and amortization decreased $3.3 million, or 1.4 percent, for the third quarter of 2012 and $2.0 million, or 0.3 percent, for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The decreases are primarily due to a change in depreciation lives for certain assets to reflect the settlements in the Minnesota and South Dakota electric rate cases, partially offset by normal system expansion across Xcel Energy's service territories. This change in depreciation lives resulted in a reduction in depreciation expense of approximately $8 million for the third quarter of 2012 and approximately $24 million for the nine months ended Sept. 30, 2012.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $11.6 million, or 13.1 percent, for the third quarter of 2012 and $27.8 million, or 10.0 percent, for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The increases are due to an increase in property taxes primarily in Minnesota. Higher property taxes in Colorado related to the electric retail business are being deferred, based on the multi-year rate settlement that was approved by the CPUC in May 2012.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased $8.2 million for the third quarter of 2012 and $9.0 million for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The increases are primarily due to the expansion of PSCo's transmission facilities, additional construction related to the CACJA and normal system expansion.

Interest Charges — Interest charges increased $5.7 million, or 3.9 percent, for the third quarter of 2012 and $18.8 million, or 4.3 percent, for the nine months ended Sept. 30, 2012, compared with the same periods in 2011. The increases are due to higher long-term debt levels to fund investment in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense increased $9.5 million for the third quarter of 2012, compared with the same period in 2011. The increase in income tax expense was primarily due to an increase in pretax income in 2012, partially offset by a one time tax benefit related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. The effective tax rate was 33.8 percent for the third quarter of 2012 compared with 36.4 percent for the same period in 2011. The lower effective tax rate for 2012 was primarily due to the adjustment referenced above. The effective tax rate would have been 36.6 percent for the third quarter of 2012 without this tax benefit.

Income tax expense decreased $9.7 million for the first nine months of 2012, compared with the same period in 2011. The decrease in income tax expense was primarily due to one time adjustments for a tax benefit associated with a carryback and a tax benefit related to the restoration of a portion of the tax benefit written off in 2010 associated with federal subsidies for prescription drug plans. As a result, Xcel Energy recognized discrete tax benefits of approximately $14.9 million for the carryback and $17 million for the tax benefit associated with the federal subsidies. These were partially offset by higher pretax income in 2012. The effective tax rate for continuing operations was 33.2 percent for the nine months ended Sept. 30, 2012 compared with 35.8 percent for the same period in 2011. The effective tax rate would have been 36.0 percent for the nine months ended Sept. 30, 2012 without these tax benefits.

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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 System Resource Plans — In December 2011, NSP Minnesota filed an update to its resource plan with the MPUC. NSP Minnesota modified the current plan to include a recommendation to withdraw the Black Dog repowering project certificate of need (CON) and to reassess the wind procurement plan and resource contingency plan in detail to account for slower projected growth and the loss of NSP-Wisconsin's wholesale customers. In May 2012, the ALJ recommended the MPUC grant NSP Minnesota's request to withdraw the CON application; the matter has been pending MPUC action. The Department of Commerce and NSP-Minnesota's most recent analyses indicate the need for 400 to 600 MW of new NSP System generating capacity later in the decade. The NSP System is the integrated electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, managed by NSP-Minnesota. In August 2012, NSP-Minnesota recommended to the MPUC to reconvene the CON proceeding with a modified scope to reflect the MPUC's forthcoming Resource Plan Order. See additional discussion within the Prairie Island Nuclear Extended Power Uprate section below.

CapX2020 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 borne by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

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, the Bemidji, Minn. to Grand Rapids, Minn. project and for the portions of the new transmission lines between Hampton, Minn. and La Crosse, Wis. to be constructed in Minnesota. In June 2011, the SDPUC approved a facility permit for a portion of the Brookings, S.D. project. The North Dakota Public Service Commission (NDPSC) granted a certificate of public convenience and necessity (CPCN) in January 2011, and a Certificate of Corridor Compatibility and Route Permit for the portion of the line in North Dakota in September 2012. In October 2012, several parties appealed the NDPSC's order for the CPCN. NSP-Minnesota expects to oppose the appeal.

In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Fargo 345 KV project was placed in service and MISO granted the final approval of the Brookings, S.D. project as a multi-value project (MVP). In September 2012, the Bemidji, Minn. to Grand Rapids, Minn. 230 KV line was placed in service.

NSP-Wisconsin

CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the CapX2020 Hampton, Minn. to La Crosse, Wis. 345 KV project on May 30, 2012. The Wisconsin portion consists of approximately 50 miles of new transmission line. The PSCW also approved a route and the cost is estimated at $211 million. Construction on the Wisconsin portion of the line is anticipated to begin in 2013 and the line is expected to go into service in 2015.

In June 2012, approximately 20 petitions for rehearing were filed with the PSCW by intervenors and interested parties. The petitions were denied by the PSCW on July 17, 2012. In August 2012, two intervenors filed a joint petition for judicial review of the PSCW's order in Dane County Circuit Court, and the PSCW filed a motion to strike the petition. NSP-Wisconsin, Dairyland Power Cooperative and WPPI Energy filed a notice of appearance and statement of position in the Dane County Circuit Court, but waived their right to brief the issues in the PSCW's motion. The PSCW's motion is currently pending. The timing of a final court ruling is uncertain.

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PSCo

Resource Plan — PSCo's 2011 electric resource plan identified relatively low resource needs beginning in 2017, and proposed filling these needs with a competitive resource acquisition process. The CPUC is expected to consider the resource plan in two phases. In the first phase, the CPUC is expected to review planning assumptions, competitive bidding structure, and determine if PSCo should acquire generation technology. The first phase is expected to be completed by the end of 2012 or early 2013. In the second phase, PSCo expects to conduct the competitive acquisition process, which is expected to be submitted to the CPUC for approval in 2013.

In July 2012, PSCo filed two separate applications which, if approved, would update the existing resources considered in its resource plan. The first is an application to purchase Brush Power, LLC and all of its assets including Brush generating Units 1, 3 and 4 for a total purchase price of approximately $75 million. Located in Brush, Colo., the generating units have a total capacity of 237 MW, including Brush Unit 1, a 60 MW combined-cycle unit; Brush Unit 3, a 30 MW simple-cycle unit; and Brush Unit 4, a 147 MW combined-cycle unit. The purchase is subject to various regulatory approvals including that of the CPUC and the FERC. In September 2012 this application was approved by the FERC. The Brush units currently provide energy and capacity to PSCo under purchased power agreements that are set to expire in 2017 for Brush Unit 1 and Brush Unit 3, and 2022 for Brush Unit 4. The transaction, if approved, is expected to result in savings to wholesale and retail customers.

The second application seeks approval to retire Arapahoe Unit 4, a 109 MW coal-fired company-owned generating station at the end of 2013. This would be an alternative to permanently fuel switching Arapahoe Unit 4 to natural gas and instead replacing the capacity and associated energy with a natural gas purchased power agreement with an existing generator. The CPUC combined all three applications and will hold hearings in late October and early November. A decision on all of these applications is expected in January 2013.

Renewable Energy Standard (RES) Compliance Plan — Colorado law mandates that at least 30 percent of PSCo's energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. PSCo has filed its 2012 and 2013 RES compliance plan. PSCo proposed to acquire up to 30 MW of customer-sited solar projects each year and up to 6 MW of community scale solar projects. In March 2012, the ALJ issued a recommended decision largely approving PSCo's proposed levels of acquisition which was affirmed by the CPUC in June 2012. PSCo has sought reconsideration of the order regarding the limit on the amounts that can be advanced to the RESA each year to cover the incremental costs of renewable energy. The CPUC agreed with PSCo that the limitation is a soft cap. PSCo expects to have expenditures well below the soft cap this year due to REC trading margins significantly offsetting expenses. The CPUC also approved moving solely to a pay-for-performance basis under the Solar*Rewards distributed solar generation program, which PSCo implemented in June 2012. The CPUC approved PSCo's proposal to implement a solar gardens program called Solar*Rewards Community, which will allow customers who either cannot or who prefer not to install solar generation on their property to join together to build a common solar facility and receive a credit on their electric bill.

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

In September 2012, the EPA formally approved the Colorado SIP for regional haze, including the changes at the PSCo plants.

PSCo's plan as of Sept. 30, 2012 is as follows:

- Cherokee Units 2 and 1 were shut down in 2011 and 2012, respectively, and Cherokee Unit 3 (365 MW in total) is expected to be shut down by the end of 2016, after a new natural gas combined cycle unit is built at Cherokee Station (569 MW);
- Cherokee Unit 2 was converted to a synchronous condenser to support the transmission system in 2012;
- Fuel switch Cherokee Unit 4 (352 MW) to natural gas by 2017;
- Shutdown Arapahoe Unit 3 (45 MW) and Unit 4 (111 MW) in 2013;
- Shutdown Valmont Unit 5 (186 MW) in 2017;
- Install selective catalytic reduction (SCR) for controlling NOx and a scrubber for controlling SO_2 on Pawnee Generating Station in 2014; and
- Install SCRs on Hayden Unit 1 in 2015 and Hayden Unit 2 in 2016.

PSCo has received CPCNs for the conversion of Cherokee Unit 2 to a synchronous condenser, for the decommissioning of Cherokee Unit 1 and Unit 2, for the Pawnee emissions controls, for the SCRs on the Hayden units and for the new natural gas combined-cycle unit at Cherokee Station.

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PSCo retired Cherokee Units 1 and 2, and is in the process of decommissioning these plants. Separately, in July 2012, PSCo sought approval to modify the original plan to retire Arapahoe Units 3 and 4. Subsequent transmission studies have determined that the synchronous condenser on Arapahoe Unit 3 is not needed for transmission system reliability given other upgrades to the system. PSCo recently filed a settlement related to Arapahoe Unit 3 with the CPUC and is awaiting approval. PSCo has also found that a purchased power agreement with an existing generator is more cost effective than operating Arapahoe Unit 4 on natural gas. Decisions on both applications are expected in the first quarter of 2013.

SmartGridCity™ (SGC) Cost Recovery — PSCo requested recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred to develop and operate SGC as part of its 2010 electric rate case. In February 2011, the CPUC allowed recovery of approximately $28 million of the capital cost and all of the O&M costs.

In December 2011, PSCo requested CPUC approval for the recovery of the remaining capital investment in SGC and also provided the additional information requested. In June 2012, the City of Boulder and the Colorado Office of Consumer Counsel filed testimony and recommended the CPUC deny PSCo's request for recovery of the remaining portion of the SGC investment. The ALJ is expected to recommend a decision in the fourth quarter of 2012. Parties will have an opportunity to appeal the ALJ's recommended decision by filing exceptions. The CPUC will consider the recommendation from the ALJ as well as the positions of the parties before they render a decision. If no party seeks exceptions, the ALJ's decision will become final.

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) —The FERC issued Orders 1000, 1000-A, and 1000-B adopting new requirements for transmission planning, cost allocation, and development to be effective prospectively. The requirements for transmission planning and cost allocation were addressed by revisions to the MISO Tariff for NSP-Minnesota and NSP-Wisconsin as discussed below in MISO Transmission Pricing; and Xcel Energy expects the requirements will be addressed by revisions to the SPP Tariff for SPS. PSCo submitted its compliance filing in October 2012, proposing to comply through participation in WestConnect, a consortium of utilities in the Western Interconnection. The filing is pending FERC action.

In April 2012, Minnesota's 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 limited impacts on future transmission development and ownership in the NSP System in Minnesota, North Dakota, and South Dakota. The impacts of the new requirements relating to future transmission development and ownership in Wisconsin are uncertain. Xcel Energy believes that statutes in Texas also protect the right of incumbent utilities to construct and own transmission interconnected to their systems, so Xcel Energy does not expect that this aspect of Order 1000 will impact the portion of SPS in Texas. However, the portion of SPS in New Mexico and PSCo may be impacted by the provisions of Order 1000 that impact an incumbent's right to build transmission because neither New Mexico nor Colorado has legislation protecting the rights of utilities to develop transmission projects in their service areas.

La Crosse, Wis. to Madison, Wis. Transmission Line Complaint — In February 2012, Xcel Energy Services 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 stated that MISO had determined that the line is to be owned by NSP-Wisconsin and American Transmission Company LLC (ATC) under the terms of the MISO Transmission Owners Agreement (TOA) and Tariff. However, ATC asserted a different interpretation of the TOA and Tariff provisions that would effectively deny NSP-Wisconsin the ability to invest $175 million in the proposed multi-value project. In July 2012, the FERC granted Xcel Energy Services Inc.'s and NSP-Wisconsin's complaint, ruling that the responsibilities to construct the La Crosse, Wis. to Madison, Wis. transmission line belong equally to both parties, NSP-Wisconsin and ATC. In August 2012, ATC requested rehearing and that the FERC grant a stay of the ruling. On Sept. 17, 2012, the FERC granted rehearing for purposes of further consideration but did not grant a stay. Thus, the July ruling remains in effect pending the FERC's further ruling on rehearing.

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ATC Complaint vs. Xcel Energy Services Inc. re Hampton, Minn. – La Crosse, Wis. Transmission Line — In October 2012, ATC filed a complaint against MISO, Xcel Energy Services Inc., NSP-Minnesota and NSP-Wisconsin, alleging that, under the legal principles set forth in the July 2012 FERC ruling in the La Crosse, Wis. Madison, to Wis. Transmission line complaint against ATC, that the FERC should determine that MISO should have designated the Hampton, Minn. to La Crosse, Wis. CapX2020 345 KV line and the La Crosse, Wis. to Madison, Wis. 345 KV line as a single facility under the MISO TOA and Tariff, and ATC thus should have been designated as the owner of the La Crosse, Wis. to Madison, Wis. line portion of the purported single facility. Xcel Energy believes the ATC complaint is without merit, and filed an answer seeking dismissal of the ATC complaint on Oct. 22, 2012.

MISO Transmission Pricing — The MISO Tariff presently provides for different allocation methods for the costs of new transmission investments: some lower voltage projects are fully allocated to loads near the project vicinity, and other reliability projects are allocated 20 percent regionally and 80 percent to local loads. If a project qualifies as a MVP, the costs would be fully allocated to all loads in the MISO region. MVP eligibility is generally obtained for higher voltage (345 KV and higher) projects expected to provide multiple purposes, such as improved reliability, reduced congestion, transmission for renewable energy, and load serving. Certain parties have appealed the FERC MVP tariff orders to the Seventh Circuit Court of Appeals.

In its Order 1000 compliance filing in October 2012, MISO proposed that all future reliability projects be fully allocated to the zone(s) in which the project is located (rather than allocating costs more broadly). MVP projects would continue to be eligible for regional cost allocation.   The NSP System has certain new transmission facilities for which other customers in MISO contribute to cost recovery. Likewise, the NSP System also pays a share of the costs of projects constructed by other transmission owning entities. The transmission revenues received by the NSP System from MISO, and the transmission charges paid to MISO, associated with projects subject to regional cost allocation could be significant in future periods.

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 generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 could impact the NRC's deliberations on NSP-Minnesota's power uprates and could also result in additional regulation, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that has developed recommendations on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures, and licensing processes. In July 2011, the task force released its recommendations in a written report which recommends actions to enhance U.S. nuclear generating plant readiness to safely manage severe events.

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. NSP-Minnesota expects that complying with these requirements will cost approximately $20 to $50 million at the Monticello and

Prairie Island plants. 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.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed them to prepare an environmental impact statement if there are significant impacts or an environmental assessment to support a finding of no significant impact. In September 2012, the NRC Commissioners directed the NRC Staff to develop an environmental impact statement (EIS) and a revised WCD and rule on the temporary storage of spent nuclear fuel. The EIS and rule are to be completed within 24 months. NSP-Minnesota has reviewed the D.C. Circuit decision and the NRC's actions in response to that decision and believes that there will not be an immediate impact on operations at the Prairie Island or Monticello nuclear generating plants.

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Prairie Island Independent Spent Fuel Storage Installation License Renewal — The current license to operate an Independent Spent Fuel Storage Installation (ISFSI) at Prairie Island expires in October 2013. An application to renew the ISFSI license for an additional 40 years until 2053 was submitted by NSP-Minnesota to the NRC in October 2011. In August 2012 the Prairie Island Indian Community (PIIC) petitioned to intervene and filed contentions with the NRC. In September 2012 the NRC named an Atomic Safety and Licensing Board (ASLB) to review the PIIC's request to intervene and contentions. The PIIC's standing to intervene was not challenged by any of the parties. The ASLB will now review the arguments and decide which if any of the contentions are admissible.

Nuclear Plant Power Uprates

Prairie Island Nuclear Extended Power Uprate — In 2009, the MPUC granted NSP-Minnesota a CON for an extended power uprate project at the Prairie Island nuclear generating plant. The total estimated cost of the extended power uprate is $294 million of which approximately $59 million has been incurred. The December 2011 resource plan update notified the MPUC that there were changes in the size, timing, and cost estimates for this project. In March 2012, NSP-Minnesota made a change of circumstances (COC) filing and provided revised economic and project design analysis. Public comments have been received both in support of and challenging the continuation of the project. On Oct. 22, 2012, NSP-Minnesota filed a supplement to the March 2012 COC which included the estimated impact of revised scheduled outages. The information indicates further reduction to the estimated benefit of the uprate project and provides NSP-Minnesota's conclusion that further investment in this project will not benefit customers. However, NSP-Minnesota reaffirmed its willingness to proceed with the uprate if the MPUC reaches a different conclusion.

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 generating plant. The MPUC approved the CON for the extended power uprate in 2008. The license amendment 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. In September 2012, NSP-Minnesota made a supplemental filing to the NRC to address the containment accident pressure concern, as part of its application to amend the operating license to allow the power uprate. NSP-Minnesota hopes to receive 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 Sept. 30, 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.

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.

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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.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various 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.

At Sept. 30, 2012, the fair values by source for the commodity trading net asset balances were as follows:

	Futures / Forwards					
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 5,999	$ 18,091	$ 1,426	$ 1,427	$ 26,943
PSCo	1	474	473	-	-	947
		$ 6,473	$ 18,564	$ 1,426	$ 1,427	$ 27,890

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

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2012	2011
Fair value of commodity trading net contract assets	$ 20,424	$ 20,249

outstanding at Jan. 1				
Contracts realized or settled during the period		(9,778)		(9,064)
Commodity trading contract additions and changes during period		17,244		10,803
Fair value of commodity trading net contract assets outstanding at Sept. 30	$	27,890	$	21,988

At Sept. 30, 2012, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.5 million.

Xcel Energy Inc.'s utility subsidiaries' 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 Sept. 30	VaR Limit	Average	High	Low
2012	$0.46	$3.00	$0.51	$1.21	$0.19
2011	0.17	3.00	0.12	0.32	0.04

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.

In conjunction with the NSP-Minnesota debt issuance in August 2012, NSP-Minnesota settled interest rate hedging instruments with a notional amount of $225 million during the three months ended Sept. 30, 2012 with cash payments of $45.0 million. In conjunction with the PSCo debt issuance in September 2012, PSCo settled interest rate hedging instruments with a notional amount of $250 million during the three months ended Sept. 30, 2012 with cash payments of $44.7 million. These losses are classified as a component of accumulated other comprehensive loss on the consolidated balance sheet, net of tax, and will be reclassified to earnings over the term of the hedged interest payments. See Note 7 for further discussion of long-term borrowings.

At Sept. 30, 2012, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $4.2 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 Sept. 30, 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. 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. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, 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 Sept. 30, 2012, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $10.7 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $13.7 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.

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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 Sept. 30, 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 Sept. 30, 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 1.3 percent and 6.6 percent, respectively, of total assets and liabilities measured at fair value at Sept. 30, 2012.

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 $27.6 million and $1.8 million of estimated fair values, respectively, for FTRs held at Sept. 30, 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 Sept. 30, 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 $128.3 million in the nuclear decommissioning fund at Sept. 30, 2012 (approximately 5.9 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	Nine Months Ended Sept. 30 2012	2011
Net cash provided by operating activities	$1,572	$1,924

Net cash provided by operating activities decreased by $352 million for the nine months ended Sept. 30, 2012, compared with the nine months ended Sept. 30, 2011. The decrease was the result of changes in working capital due to the timing of payments and receipts, higher pension contributions, interest rate swap settlements and the effect of income taxes paid in 2012 compared to a refund received in 2011, partially offset by higher net income.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2012	2011
Net cash used in investing activities	$(1,610)	$(1,661)

Net cash used in investing activities decreased by $51 million for the nine months ended Sept. 30, 2012, compared with the nine months ended Sept. 30, 2011. The decrease was the result of the change in restricted cash due to customer refunds associated with the nuclear waste disposal settlement with the U.S. Department of Energy, partially offset by higher capital expenditures and insurance proceeds related to Sherco Unit 3 received in 2012.

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(Millions of Dollars)	Nine Months Ended Sept. 30 2012	2011
Net cash provided by (used in) financing activities	$724	$(177)

Net cash provided by financing activities increased by $901 million for the nine months ended Sept. 30, 2012, compared with the nine months ended Sept. 30, 2011. The increase was primarily due to higher proceeds from short-term borrowings and the issuance of long-term debt, partially offset by repayments of previously existing long-term debt, 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.

Capital Expenditures — The estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2013 through 2017 are shown in the table below.

(Millions of Dollars)	2013	2014	2015	2016	2017
By Subsidiary					
NSP-Minnesota	$1,440	$1,160	$950	$970	$1,130
PSCo	1,075	1,000	850	800	840
SPS	490	400	305	300	345
NSP-Wisconsin	180	240	245	230	235
WYCO	15	-	-	-	-
Total capital expenditures	$3,200	$2,800	$2,350	$2,300	$2,550
By Function	2013	2014	2015	2016	2017
Electric transmission	$1,070	735	$590	$510	$620
Electric generation	1,010	870	650	635	770
Electric distribution	515	525	525	535	545
Natural gas	355	365	335	325	320
Nuclear fuel	95	155	100	140	145
Other	155	150	150	155	150
Total capital expenditures	$3,200	$2,800	$2,350	$2,300	$2,550
By Project	2013	2014	2015	2016	2017
Other capital expenditures	$1,710	$1,610	$1,555	$1,600	$1,755
CapX2020 transmission project	350	295	140	-	-
PSCo CACJA	345	235	90	15	-
Nuclear capacity increases and life extension	315	75	100	95	100
Other major transmission projects	245	260	175	320	415
Natural gas pipeline replacement	140	170	190	130	135
Nuclear fuel	95	155	100	140	145
Total capital expenditures	$3,200	$2,800	$2,350	$2,300	$2,550

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

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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. In April 2012, the CFTC ruled that swap dealing activity conducted by companies under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the de minimis exemption level and will not subject the company to registering as a swap dealer. Xcel Energy's current and projected swap activity is below this de minimis level. The CFTC has set a $25 million de minimis exemption for swaps with "Special Entities," as defined by the CFTC primarily government entities, after which the entity would have to register as a swap dealer. This small limit for swap activity with "Special Entities" could reduce the volume of activity Xcel Energy conducts with such entities. 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. The full implications for Xcel Energy can not yet be determined until all the definitions and rulemakings are completed and legal reviews are conducted by Xcel Energy. As currently proposed, Xcel Energy will be subject to reporting requirements on April 10, 2013.

FERC Order 741 addresses rulemaking addressing the credit policies of organized electric markets and limits the amount of overall credit available to entities operating and places restrictions on netting of transactions within organized markets unless certain market protocols are implemented by the RTO. The various RTOs have filed their proposed market protocols to satisfy FERC Order 741 and the proposed new market design for MISO was approved by the FERC. It is expected that having MISO serve as the central counterparty will allow for certain types of netting within the RTO and reduce Xcel Energy's overall credit and margin exposure.

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.

Long Term Contracts — PSCo entered into a 10 year physical gas supply contract from November 2013 through October 2023; this contract will help meet a portion of the annual natural gas supply requirements for both PSCo's electric utility and natural gas utility. The purchase price for natural gas under the contract is indexed-based. Given current input assumptions, the notional value of the transaction over the duration of the contract is approximately $1.2 billion.

Long-Term Debt

SPS — In June 2012, SPS issued an additional $100 million of its 4.50 percent first mortgage bonds due Aug. 15, 2041. Including the $200 million of this series previously issued in August 2011, total principal outstanding for this series is $300 million.

NSP-Minnesota — In August 2012, NSP-Minnesota issued $300 million of 2.15 percent first mortgage bonds due Aug. 15, 2022, as well as $500 million of 3.40 percent first mortgage bonds due Aug. 15, 2042. NSP-Minnesota used a portion of the net proceeds from the first mortgage bonds to repay $450 million of 8.0 percent first mortgage bonds maturing on Aug. 28, 2012 and to redeem the following series of pollution control bonds: $100 million of 8.50 percent bonds due Sept. 1, 2019, $27.9 million of 8.50 percent bonds due March 1, 2019 and $69 million of 8.50 percent bonds due April 1, 2030.

PSCo — In September 2012, PSCo issued $300 million of 2.25 percent first mortgage bonds due Sept. 15, 2022, as well as $500 million of 3.60 percent first mortgage bonds due Sept. 15, 2042. PSCo used a portion of the net proceeds from the first mortgage bonds to redeem $600 million of 7.875 percent first mortgage bonds maturing on Oct. 1, 2012, and intends to redeem $48.75 million of 5.10 percent bonds due Jan. 1, 2019, for which a notice of full optional redemption was issued to bondholders on Oct. 1, 2012.

NSP-Wisconsin — In October 2012, NSP-Wisconsin issued $100 million of 3.70 percent first mortgage bonds due Oct. 1, 2042.

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.

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Short Term Investments — Xcel Energy Inc., NSP Minnesota, NSP Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Sept. 30, 2012, approximately $638.9 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:

(Millions of Dollars, Except Interest Rates)	Three Months Ended Sept. 30, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	304	219
Average amount outstanding	433	430
Maximum amount outstanding	630	824
Weighted average interest rate, computed on a daily basis	0.34%	0.36%
Weighted average interest rate at period end	0.34	0.40

Credit Facilities — As of Oct. 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	$ 216.0	$ 584.0	$ 0.1	$ 584.1
PSCo	700.0	4.0	696.0	0.3	696.3
NSP-Minnesota	500.0	66.7	433.3	0.5	433.8
SPS	300.0	-	300.0	0.8	300.8
NSP-Wisconsin	150.0	10.0	140.0	0.2	140.2
Total	$ 2,450.0	$ 296.7	$ 2,153.3	$ 1.9	$ 2,155.2

(a) These credit facilities expire in July 2017.
(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.

2012 Financing — 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 completed the following financing in 2012:

- In June, SPS issued $100 million of 30-year first mortgage bonds with a coupon of 4.50 percent.
- In August, NSP-Minnesota issued $300 million of 10-year first mortgage bonds with a coupon of 2.15 percent, and $500 million of 30-year first mortgage bonds with a coupon of 3.40 percent.
- In September, PSCo issued $300 million of 10-year first mortgage bonds with a coupon of 2.25 percent, and $500 million of 30-year first mortgage bonds with a coupon of 3.60 percent.
- In October, NSP-Wisconsin issued $100 million of 30-year first mortgage bonds with a coupon of 3.70 percent.

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Credit Ratings — Access to reasonably priced capital markets is dependent in part on credit and ratings. In 2011, Moody's placed SPS on negative outlook. On Oct. 8, 2012, Moody's downgraded SPS by one notch, based on the expected moderation of SPS' credit metrics due to high levels of capital expenditures and regulatory lag. The outlook is now stable.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy's 2012 ongoing earnings guidance range is $1.75 to $1.85 per share. Xcel Energy anticipates that 2012 GAAP earnings will be in the upper 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 remaining rate case and regulatory proceedings.
- 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 decline by approximately 1 percent.
- Rider revenue recovery for certain projects have been rolled into base rates, therefore the change is no longer meaningful.
- O&M expenses are projected to increase approximately 2 percent over 2011 levels.
- Depreciation and amortization expense is projected to increase $40 million to $45 million over 2011 levels.
- Property taxes are projected to increase $25 million to $30 million over 2011 levels.
- Interest expense (net of AFUDC — debt) is projected to increase approximately $0 to $10 million.
- AFUDC — equity is projected to increase approximately $15 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.

Xcel Energy's 2013 ongoing earnings guidance is $1.85 to $1.95 per share. Key assumptions related to 2013 ongoing earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales are projected to grow approximately 0.5 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline by approximately 1 percent.
- Rider revenue recovery for certain projects have been rolled into base rates, therefore the change is no longer meaningful.
- O&M expenses are projected to increase approximately 4 percent to 5 percent over 2012 projected levels.
- Depreciation expense is projected to increase $70 million to $80 million over 2012 projected levels.
- Property taxes are projected to increase approximately $35 million over projected 2012 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $30 million to $35 million from 2012 projected levels.
- AFUDC — equity is projected to increase approximately $15 million to $20 million over 2012 projected levels.
- The effective tax rate is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 490 million to 500 million shares.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

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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 Sept. 30, 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.

Item 1A — RISK FACTORS

Except to the extent updated or described below, 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.

Public Policy Risks

Increased taxation of dividends could adversely impact our share price

An increase in taxes associated with dividends could impact an investor's behavior or investment strategy. Currently, the maximum tax rate on qualified dividends for individuals is 15 percent. Unless current tax laws are extended or amended, dividend income from regular C corporations is scheduled to be taxed as ordinary income after December 31, 2012. We cannot predict whether in fact this will occur or, if it occurs, what the impact will be on our share price, or ability to finance our capital investment programs.

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

None.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

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Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
4.01*	Supplemental Indenture dated as of Aug. 1, 2012 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $300 million principal amount of 2.15 percent First Mortgage Bonds, Series due Aug. 15, 2022 and $500 million principal amount of 3.40 percent First Mortgage Bonds, Series due Aug. 15, 2042 (Exhibit 4.01 to NSP-Minnesota's Form 8-K dated Aug. 13, 2012 (file no. 001-31387)).
4.02*	Supplemental Indenture dated as of Sept. 1, 2012 between PSCo and U.S. Bank National Association, as successor Trustee, creating $300 million principal amount of 2.25 percent First Mortgage Bonds, Series No. 23 due 2022 and $500 million principal amount of 3.60 percent First Mortgage Bonds, Series No. 24 due 2042 (Exhibit 4.01 to PSCo's Form 8-K dated Sept. 11, 2012 (file no. 001-03280)).
10.01*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.01 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).
10.02*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.02 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).
10.03*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.03 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).
10.04*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.04 to Form 8-K, dated July 27, 2012 (file no. 001-03034)).
10.05*	Amended and Restated Credit Agreement, dated as of July 27, 2012 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.05 to Form 8-K, dated July 27, 2012 (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 Sept. 30, 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.

Oct. 26, 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)