XCEL ENERGY INC
Form 10-Q
October 29, 2010

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

FORM 10-Q

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

For the quarterly period ended Sept. 30, 2010
or

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

Commission File Number: 1-3034

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

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

Non-accelerated filer £ (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). £Yes TNo

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. 21, 2010
Common Stock, $2.50 par value	460,112,922 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, a Colorado corporation (PSCo); and Southwestern Public Service Company, a New Mexico corporation (SPS). 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, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
Operating revenues				
Electric	$ 2,440,917	$ 2,128,955	$ 6,477,211	$ 5,749,207
Natural gas	170,594	169,601	1,210,154	1,224,161
Other	17,276	16,006	56,648	52,819
Total operating revenues	2,628,787	2,314,562	7,744,013	7,026,187
Operating expenses				
Electric fuel and purchased power	1,110,781	982,103	3,085,347	2,703,952
Cost of natural gas sold and transported	66,571	71,638	774,647	809,791
Cost of sales — other	8,848	4,915	21,244	14,268
Other operating and maintenance expenses	509,634	466,465	1,507,247	1,410,760
Conservation and demand side management program expenses	60,861	47,157	174,451	133,793
Depreciation and amortization	221,671	198,222	639,303	609,285
Taxes (other than income taxes)	81,791	78,914	244,175	229,025
Total operating expenses	2,060,157	1,849,414	6,446,414	5,910,874
Operating income	568,630	465,148	1,297,599	1,115,313
Other income (expense), net	27,450	(977)	30,134	4,394
Equity earnings of unconsolidated subsidiaries	7,670	4,363	22,433	10,760
Allowance for funds used during construction — equity	13,464	18,618	39,750	55,565
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,229, $5,103, $15,386 and $15,255, respectively	144,849	139,347	430,134	420,447
Allowance for funds used during construction — debt	(6,323)	(9,598)	(20,635)	(29,671)
Total interest charges and financing costs	138,526	129,749	409,499	390,776
Income from continuing operations before income taxes	478,688	357,403	980,417	795,256
Income taxes	166,200	135,610	364,964	280,581
Income from continuing operations	312,488	221,793	615,453	514,675
Income (loss) from discontinued operations, net of tax	(182)	(965)	3,747	(2,673)
Net income	312,306	220,828	619,200	512,002
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180
Earnings available to common shareholders	$ 311,246	$ 219,768	$ 616,020	$ 508,822
Weighted average common shares outstanding:				
Basic	460,471	456,769	459,816	456,095

Diluted	462,019	457,453	460,722	456,729
Earnings per average common share — basic:				
Income from continuing operations	$ 0.68	$ 0.48	$ 1.33	$ 1.12
Income from discontinued operations	-	-	0.01	-
Earnings per share	$ 0.68	$ 0.48	$ 1.34	$ 1.12
Earnings per average common share — diluted:				
Income from continuing operations	$ 0.67	$ 0.48	$ 1.33	$ 1.11
Income from discontinued operations	-	-	0.01	-
Earnings per share	$ 0.67	$ 0.48	$ 1.34	$ 1.11
Cash dividends declared per common share	$ 0.25	$ 0.25	$ 0.75	$ 0.73

See Notes to Consolidated Financial Statements

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

	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
Operating activities		
Net income	$ 619,200	$ 512,002
Remove (income) loss from discontinued operations	(3,747)	2,673
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	648,089	622,563
Conservation and demand side management program expenses	18,694	21,661
Nuclear fuel amortization	78,150	59,520
Deferred income taxes	299,572	304,707
Amortization of investment tax credits	(4,782)	(5,213)
Allowance for equity funds used during construction	(39,750)	(55,565)
Equity earnings of unconsolidated subsidiaries	(22,433)	(10,760)
Dividends from unconsolidated subsidiaries	23,821	20,999
Share-based compensation expense	27,272	13,252
Net realized and unrealized hedging and derivative transactions	(61,136)	46,298
Changes in operating assets and liabilities:		
Accounts receivable	31,670	265,655
Accrued unbilled revenues	159,769	272,574
Inventories	(25,520)	111,780
Recoverable purchased natural gas and electric energy costs	28,770	(30,792)
Other current assets	17,635	(72,817)
Accounts payable	(282,950)	(286,019)
Net regulatory assets and liabilities	56,358	20,422
Other current liabilities	(26,116)	7,347
Change in other noncurrent assets	(4,184)	(2,014)
Change in other noncurrent liabilities	(36,634)	(172,291)
Operating cash flows provided by (used in) discontinued operations	19,981	(17,166)
Net cash provided by operating activities	1,521,729	1,628,816
Investing activities		
Utility capital/construction expenditures	(1,561,987)	(1,310,686)
Allowance for equity funds used during construction	39,750	55,565
Purchase of investments in external decommissioning fund	(3,309,093)	(1,278,554)
Proceeds from the sale of investments in external decommissioning fund	3,314,356	1,276,417
Investment in WYCO Development LLC	(6,119)	(38,936)
Change in restricted cash	91	(1,389)
Other investments	2,044	3,472
Net cash used in investing activities	(1,520,958)	(1,294,111)
Financing activities		
Proceeds from (repayment of) short-term borrowings, net	(419,000)	38,750
Proceeds from issuance of long-term debt	1,038,368	394,762
Repayment of long-term debt, including reacquisition premiums	(200,452)	(620,074)

Proceeds from issuance of common stock	5,869	4,174
Dividends paid	(322,187)	(309,320)
Net cash provided by (used in) financing activities	102,598	(491,708)
Net increase (decrease) in cash and cash equivalents	103,369	(157,003)
Net increase (decrease) in cash and cash equivalents — discontinued operations	2,297	(1,989)
Cash and cash equivalents at beginning of period	107,789	249,198
Cash and cash equivalents at end of period	$ 213,455	$ 90,206
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$ (389,719)	$ (400,511)
Cash (paid) received for income taxes, net	(17,410)	21,857
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 62,663	$ 33,116
Supplemental disclosure of non-cash financing transactions:		
Issuance of common stock for reinvested dividends and 401(k) plans	$ 48,685	$ 44,668

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands of dollars)

	Sept. 30, 2010	Dec. 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 213,455	$ 107,789
Accounts receivable, net	703,960	729,409
Accrued unbilled revenues	534,280	694,049
Inventories	591,725	566,205
Recoverable purchased natural gas and electric energy costs	27,974	56,744
Derivative instruments valuation	65,573	97,700
Prepayments and other	296,097	359,560
Current assets related to discontinued operations	96,449	151,955
Total current assets	2,529,513	2,763,411
Property, plant and equipment, net	19,444,841	18,508,296
Other assets		
Nuclear decommissioning fund and other investments	1,443,300	1,381,791
Regulatory assets	2,324,744	2,287,636
Derivative instruments valuation	261,748	289,530
Other	162,473	140,367
Noncurrent assets related to discontinued operations	134,847	117,397
Total other assets	4,327,112	4,216,721
Total assets	$ 26,301,466	$ 25,488,428
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 414,443	$ 543,814
Short-term debt	40,000	459,000
Accounts payable	794,381	1,083,127
Taxes accrued	224,483	232,964
Accrued interest	161,553	157,253
Dividends payable	117,236	113,147
Derivative instruments valuation	80,929	46,554
Other	357,274	350,318
Current liabilities related to discontinued operations	9,185	29,080
Total current liabilities	2,199,484	3,015,257
Deferred credits and other liabilities		
Deferred income taxes	3,616,378	3,336,354
Deferred investment tax credits	94,508	99,290
Regulatory liabilities	1,236,097	1,222,833
Asset retirement obligations	920,129	881,479
Derivative instruments valuation	299,279	307,770
Customer advances	274,310	295,470
Pension and employee benefit obligations	830,286	838,067

Other	251,819	211,666
Noncurrent liabilities related to discontinued operations	3,760	3,389
Total deferred credits and other liabilities	7,526,566	7,196,318
Commitments and contingent liabilities		
Capitalization		
Long-term debt	8,864,759	7,888,628
Preferred stockholders' equity – authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800	104,980	104,980
Common stockholders' equity – authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: Sept. 30, 2010 – 460,104,538; Dec. 31, 2009 – 457,509,263	7,605,677	7,283,245
Total liabilities and equity	$ 26,301,466	$ 25,488,428

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity
Three Months Ended Sept. 30, 2010 and 2009						
Balance at June 30, 2009	455,717	$1,139,292	$4,727,380	$1,256,405	$ (49,354)	$ 7,073,723
Net income				220,828		220,828
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $260					365	365
Net derivative instrument fair value changes during the period, net of tax of $(3,876)					(5,557)	(5,557)
Unrealized gain - marketable securities, net of tax of $62					90	90
Comprehensive income for the period						215,726
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(112,255)		(112,255)
Issuances of common stock	534	1,337	7,485			8,822
Share-based compensation			6,224			6,224
Balance at Sept. 30, 2009	456,251	$1,140,629	$4,741,089	$1,363,918	$ (54,456)	$ 7,191,180
Balance at June 30, 2010	459,627	$1,149,069	$4,800,841	$1,493,997	$ (52,085)	$ 7,391,822
Net income				312,306		312,306
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $236					510	510
Net derivative instrument fair value changes during the period, net of tax of $554					784	784
Unrealized gain - marketable securities, net of tax of $37					54	54
Comprehensive income for the period						313,654
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(116,754)		(116,754)
Issuances of common stock	478	1,192	7,805			8,997
Share-based compensation			9,018			9,018

Balance at Sept. 30, 2010	460,105	$1,150,261	$4,817,664	$1,688,489	$ (50,737)	$ 7,605,677

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity
Nine Months Ended Sept. 30, 2010 and 2009						
Balance at Dec 31, 2008	453,792	$1,134,480	$4,695,019	$1,187,911	$ (53,669)	$ 6,963,741
Net income				512,002		512,002
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $769					1,106	1,106
Net derivative instrument fair value changes during the period, net of tax of $(1,736)					(2,226)	(2,226)
Unrealized gain - marketable securities, net of tax of $230					333	333
Comprehensive income for the period						511,215
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(332,815)		(332,815)
Issuances of common stock	2,459	6,149	25,550			31,699
Share-based compensation			20,520			20,520
Balance at Sept. 30, 2009	456,251	$1,140,629	$4,741,089	$1,363,918	$ (54,456)	$ 7,191,180
Balance at Dec. 31, 2009	457,509	$1,143,773	$4,769,980	$1,419,201	$ (49,709)	$ 7,283,245
Net income				619,200		619,200
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $852					1,385	1,385
Net derivative instrument fair value changes during the period, net of tax of $(1,711)					(2,371)	(2,371)
Unrealized loss - marketable securities, net of tax of $(29)					(42)	(42)
Comprehensive income for the period						618,172
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(346,732)		(346,732)
Issuances of common stock	2,596	6,488	23,437			29,925

Share-based compensation			24,247			24,247
Balance at Sept. 30, 2010	460,105	$1,150,261	$4,817,664	$1,688,489	$ (50,737)	$ 7,605,677

See Notes to Consolidated Financial Statements

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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 (collectively, Xcel Energy) as of Sept. 30, 2010 and Dec. 31, 2009; the results of its operations and changes in stockholders' equity for the three and nine months ended Sept. 30, 2010 and 2009; and its cash flows for the nine months ended Sept. 30, 2010 and 2009. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2010 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, 2009 balance sheet information has been derived from the audited 2009 consolidated financial statements. 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 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 Annual Report on Form 10-K for the year ended Dec. 31, 2009, filed with the SEC on Feb. 26, 2010. 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

Except to the extent updated or described below, the significant accounting policies set forth in Note 1 to the consolidated financial statements in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Reclassifications — Conservation and demand side management program expenses for the nine months ended Sept. 30, 2009 were reclassified as a separate line item from depreciation and amortization expenses within the consolidated statements of cash flows. The reclassification did not have an impact on net cash provided by operating activities.

2. Accounting Pronouncements

Recently Adopted

Consolidation of Variable Interest Entities — In June 2009, the Financial Accounting Standards Board (FASB) issued new guidance on consolidation of variable interest entities. The guidance affects various elements of consolidation, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary. These updates to the FASB Accounting Standards Codification (ASC or Codification) were effective for interim and annual periods beginning after Nov. 15, 2009. Xcel Energy implemented the guidance on Jan. 1, 2010, and the implementation did not have a material impact on its consolidated financial statements. For further information and required disclosures regarding variable interest entities, see Note 7 to the consolidated financial statements.

Fair Value Measurement Disclosures — In January 2010, the FASB issued Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements (Accounting Standards Update (ASU) No. 2010-06), which updates the Codification to require new disclosures for assets and liabilities measured at fair value. The requirements include expanded disclosure of valuation methodologies for fair value measurements, transfers between levels of the fair value hierarchy, and gross rather than net presentation of certain changes in Level 3 fair value measurements. The updates to the Codification contained in ASU No. 2010-06 were effective for interim and annual periods beginning after Dec. 15, 2009, except for requirements related to gross presentation of certain changes in Level 3 fair value measurements, which are effective for interim and annual periods beginning after Dec. 15, 2010. Xcel Energy implemented the portions of the guidance required on Jan. 1, 2010, and the implementation did not have a material impact on its consolidated financial statements. For further information and required disclosures, see Note 10 to the consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Accounts receivable, net		
Accounts receivable	$ 755,725	$ 785,512
Less allowance for bad debts	(51,765)	(56,103)
	$ 703,960	$ 729,409
Inventories		
Materials and supplies	$ 186,199	$ 172,993
Fuel	213,222	221,457
Natural gas	192,304	171,755
	$ 591,725	$ 566,205
Property, plant and equipment, net		
Electric plant	$ 23,923,771	$ 22,589,071
Natural gas plant	3,367,303	3,269,934
Common and other property	1,512,255	1,492,463
Construction work in progress	1,667,407	1,769,545
Total property, plant and equipment	30,470,736	29,121,013
Less accumulated depreciation	(11,310,973)	(10,914,509)
Nuclear fuel	1,798,905	1,737,469
Less accumulated amortization	(1,513,827)	(1,435,677)
	$ 19,444,841	$ 18,508,296

4. Discontinued Operations

Results of operations for divested businesses are reported, for all periods presented, as discontinued operations. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets associated with temporary differences and net operating loss (NOL) and tax credit carryforwards that will be deductible in future years.

The major classes of assets and liabilities related to discontinued operations are as follows:

(Thousands of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Cash	$ 10,156	$ 7,859
Deferred income tax benefits	59,993	106,770
Other current assets	26,300	37,326
Current assets related to discontinued operations	$ 96,449	$ 151,955
Deferred income tax benefits	$ 116,826	$ 95,424
Other noncurrent assets	18,021	21,973
Noncurrent assets related to discontinued operations	$ 134,847	$ 117,397
Accounts payable	$ 272	$ 445
Other current liabilities	8,913	28,635
Current liabilities related to discontinued operations	$ 9,185	$ 29,080
Noncurrent liabilities related to discontinued operations	$ 3,760	$ 3,389

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5. Income Taxes

Corporate Owned Life Insurance (COLI) — In 2007, Xcel Energy and the U.S. government settled an ongoing dispute regarding PSCo's right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by P.S.R. Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo. Xcel Energy paid the U.S. government a total of $64.4 million in settlement of the U.S. government's claims for tax, penalty, and interest for tax years 1993 through 2007. Xcel Energy surrendered the policies to its insurer on Oct. 31, 2007, without recognizing a taxable gain. As a result of the settlement, the lawsuit filed by Xcel Energy in the United States District Court has been dismissed and the Tax Court proceedings are in the process of being dismissed.

As part of the Tax Court proceedings, during the first quarter of 2010, Xcel Energy and the Internal Revenue Service (IRS) reached an agreement in principle after a comprehensive financial reconciliation of Xcel Energy's statement of account, dating back to tax year 1993. Upon completion of this review, PSRI recorded a net non-recurring tax and interest charge of approximately $10 million (including $7.7 million tax expense and $2.3 million interest expense, net of tax), during the first quarter of 2010. During the third quarter of 2010, Xcel Energy and the IRS came to final agreement on the applicable interest netting computations related to these tax years. Accordingly, PSRI recorded a reduction to expense of $0.6 million, net of tax, during the third quarter of 2010. Xcel Energy anticipates that the Tax Court proceedings will be dismissed in the fourth quarter of 2010.

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

Medicare Part D Subsidy Reimbursements — In March 2010, the Patient Protection and Affordable Care Act was signed into law. The law includes provisions to generate tax revenue to help offset the cost of the new legislation. One of these provisions reduces the deductibility of retiree health care costs to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage, beginning in 2013. Based on this provision, Xcel Energy is subject to additional taxes and is required to reverse previously recorded tax benefits in the period of enactment. Xcel Energy expensed approximately $17 million of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. Xcel Energy does not expect the $17 million of additional tax expense to recur in future periods. The 2010 effective tax rate (ETR) will increase due to additional tax expense of approximately $4 million associated with current year retiree health care accruals.

Federal Audit — Xcel Energy files a consolidated federal income tax return. During the first quarter of 2010, the IRS completed an examination of Xcel Energy's federal income tax returns of tax years 2006 and 2007. The IRS did not propose any material adjustments for those tax years. The statute of limitations applicable to Xcel Energy's 2006 federal income tax return expired in August 2010. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expires in September 2011. The IRS commenced an examination of tax years 2008 and 2009 in the third quarter of 2010. As of Sept. 30, 2010, the IRS had not proposed any material adjustments to tax years 2008 and 2009.

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, 2010, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions are as follows:

State	Year
Colorado	2004
Minnesota	2006
Texas	2005
Wisconsin	2005

In 2009, Xcel Energy received a request for information from the state of Minnesota relating to tax years 2002 through 2007 in order to determine whether to undertake an audit of those years. During the second quarter of 2010, the state of Minnesota informed Xcel Energy that the state's request for information relating to tax years 2002 through 2007 had been fulfilled. The state indicated that it does not intend to perform audit procedures on these years at this time. Also, during the second quarter of 2010, the state of Texas completed its audit of tax years 2006 and 2007. No change in tax liability was proposed. There currently are no state income tax audits in progress.

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

A reconciliation of the amount of unrecognized tax benefit related to continuing operations is as follows:

(Millions of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Unrecognized tax benefit - Permanent tax positions	$ 3.7	$ 4.0
Unrecognized tax benefit - Temporary tax positions	30.6	19.7
Unrecognized tax benefit balance	$ 34.3	$ 23.7

A reconciliation of the amount of unrecognized tax benefit related to discontinued operations is as follows:

(Millions of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Unrecognized tax benefit - Permanent tax positions	$ 0.3	$ 6.6
Unrecognized tax benefit - Temporary tax positions	-	-
Unrecognized tax benefit balance	$ 0.3	$ 6.6

The unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards that relate to continuing operations and discontinued operations were as follows:

(Millions of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Continuing operations	$ (19.5)	$ (8.9)
Discontinued operations	(13.4)	(20.4)

The increase in the unrecognized tax benefit balance reported in continuing operations of $7.7 million from June 30, 2010 to Sept. 30, 2010 and $10.6 million from Dec. 31, 2009 to Sept. 30, 2010 was due primarily to the addition of uncertain tax positions related to current and prior years' activity. Xcel Energy's amount of unrecognized tax benefits related to continuing operations 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, it is not reasonably possible to estimate an overall range of possible change.

There was no change in the unrecognized tax benefit balance related to discontinued operations from June 30, 2010 to Sept. 30, 2010. The decrease in the unrecognized tax benefit balance related to discontinued operations of $6.3 million from Dec. 31, 2009 to Sept. 30, 2010 was due to a clarification of tax law in a court ruling issued to an unrelated taxpayer, coupled with the completion of the state of Minnesota review of tax years 2002 through 2007. Xcel Energy's remaining amount of unrecognized tax benefits related to discontinued operations is not expected to change significantly in the next 12 months.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. A reconciliation of the beginning and ending amount of the payable for interest related to unrecognized tax benefits related to continuing operations is as follows:

(Millions of Dollars)	2010	2009
Payable for interest related to unrecognized tax benefits at Jan. 1	$(0.4)	$(1.9)
	(0.1)	(0.3)

Interest expense related to unrecognized tax benefits for the three months ended March 31		
Interest expense related to unrecognized tax benefits for the three months ended June 30	(0.3)	-
Interest expense related to unrecognized tax benefits for the three months ended Sept. 30	-	(0.7)
Payable for interest related to unrecognized tax benefits at Sept. 30	$(0.8)	$(2.9)

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A reconciliation of the beginning and ending amount of the receivable for interest related to unrecognized tax benefits related to discontinued operations is as follows:

(Millions of Dollars)	2010	2009
Receivable for interest related to unrecognized tax benefits at Jan. 1	$ 0.2	$ 1.5
Interest income related to unrecognized tax benefits for the three months ended March 31	0.1	0.2
Interest income related to unrecognized tax benefits for the three months ended June 30	0.2	0.1
Interest income related to unrecognized tax benefits for the three months ended Sept. 30	0.1	0.6
Receivable for interest related to unrecognized tax benefits at Sept. 30	$ 0.6	$ 2.4

No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2010 or Dec. 31, 2009.

6. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 16 to the consolidated financial statements included in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

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

Base Rate

NSP-Minnesota Gas Rate Case — In November 2009, NSP-Minnesota filed a request with the MPUC to increase Minnesota natural gas rates by $16.2 million for 2010, based on a return on equity (ROE) of 11 percent, an equity ratio of 52.46 percent and a rate base of $441 million. The overall request seeks an additional $3.5 million, effective Jan. 1, 2011, for recovery of pension funding costs necessary to comply with federal law. In December 2009, the MPUC approved an interim rate increase of $11.1 million, subject to refund. Interim rates went into effect on Jan. 11, 2010.

NSP-Minnesota made several adjustments and is currently seeking an increase of $10.0 million based on a 10.6 percent ROE. The Office of Energy Security (OES) revised its case and is now recommending an increase of approximately $7.5 million based on a 10.09 percent ROE. NSP-Minnesota and the Minnesota Office of Attorney General (OAG) agreed on treatment of pension issues, for future rate proceedings, and NSP-Minnesota is no longer seeking a 2011 step-in of pension expense. The OAG continued to recommend further adjustments in bad debt expense, distribution operating and maintenance (O&M) expenses and the cost of debt.

In October 2010, the administrative law judge (ALJ) issued his report and recommended a rate increase of approximately $8 million, based on a 10.09 percent ROE. A decision from the MPUC is anticipated late in the fourth quarter of 2010.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider — The MPUC has approved a TCR rider that allows annual adjustments to retail electric rates to provide recovery of certain incremental transmission investments between rate cases. In April 2010, the MPUC approved the 2010 TCR rider that will recover approximately $10.8 million in 2010. In October 2010, NSP-Minnesota filed its 2011 rider recovery request, seeking approval to recover approximately $12.9 million during 2011.

Renewable Energy Standard (RES) Rider — The MPUC has approved a RES rider to recover the costs for utility-owned projects implemented in compliance with the Minnesota RES. In April 2010, the MPUC approved the 2010 RES rider that resulted in $38.4 million in revenue recovery beginning May 1, 2010. In October 2010, NSP-Minnesota filed its 2011 rider recovery request, seeking approval to recover approximately $67.8 million during 2011.

State Energy Policy (SEP) Rider — In March 2010, NSP-Minnesota filed a request to recover approximately $2.5 million of Minnesota electric retail revenue requirements and $0.7 million of natural gas retail revenue requirements during the July 2010-June 2011 timeframe related to SEP mandates. In September 2010, the MPUC issued an order approving NSP-Minnesota’s petition with a rate implementation date of Oct. 1, 2010.

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Metropolitan Emissions Reduction Project (MERP) Rider — In December 2009, the MPUC authorized NSP-Minnesota to recover the 2010 revenue requirements related to environmental improvement projects amounting to approximately $116.7 million in 2010 through the MERP rider. In October 2010, NSP-Minnesota filed a request to recover approximately $111.4 million during 2011. Final MPUC action is pending.

Renewable Development Fund (RDF) Rider — The MPUC has approved an RDF rider that allows annual adjustments to retail electric rates to provide for the recovery of RDF program and project expenses. In June 2010, the MPUC authorized NSP-Minnesota to recover $22.9 million in RDF expenses in 2010 through the RDF rider. The primary components of RDF costs are legislatively mandated expenses such as renewable energy production incentive payments, RDF grant project payments, and RDF program administrative costs. In October 2010, NSP-Minnesota filed its annual request to recover $19.2 million in expenses for 2011. Final MPUC action is pending.

Annual Automatic Adjustment Report for 2008/2009 — In September 2009, NSP-Minnesota filed its annual electric and natural gas automatic adjustment reports for July 1, 2008 through June 30, 2009. During that time period, $803.6 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the fuel clause adjustment (FCA). In addition, approximately $499.4 million of purchased natural gas and transportation costs were recovered from Minnesota natural gas customers through the purchased gas adjustment (PGA). In June 2010, the OES filed comments recommending approval of the 2008/2009 natural gas automatic adjustment report. FCA and PGA recovery remains provisional and potentially subject to refund until the MPUC issues an order approving the automatic adjustment report for the period. Final MPUC action is pending.

Annual Automatic Adjustment Report for 2009/2010 — In September 2010, NSP-Minnesota filed its annual electric and natural gas automatic adjustment reports for July 1, 2009 through June 30, 2010. During that time period, $749.5 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the FCA. In addition, approximately $354.5 million of purchased natural gas and transportation costs were recovered from Minnesota natural gas customers through the PGA. FCA and PGA recovery remains provisional and potentially subject to refund until the MPUC issues an order approving the automatic adjustment report for the period. Final MPUC action is pending.

NSP-Wisconsin

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

2010 Electric Fuel Cost Recovery — Pursuant to Wisconsin fuel rules, in May 2010, the PSCW set NSP-Wisconsin's electric rates subject to refund with interest at 10.40 percent, pending a full review of 2010 fuel costs. The PSCW has not begun its review of 2010 fuel costs. NSP-Wisconsin's fuel and purchased power costs through September 2010 were approximately $2.0 million, or 1.5 percent, lower than authorized in the 2010 electric rate case, which is within the cumulative variance range for the monitored fuel costs established by the PSCW. However, based on forecasts for the remainder of 2010, NSP-Wisconsin could exceed the 2.0 percent variance range and be required to provide a refund to customers. NSP-Wisconsin has established a liability of $1.4 million for such amounts subject to refund collected through Sept. 30, 2010.

2010 Electric Rate Case Reopener — In August 2010, NSP-Wisconsin filed a request with the PSCW to reopen the 2010 rate case and increase retail electric rates for 2011 by $29.1 million, or 5.4 percent, based on a forecast 2011 test year. The requested increase in electric rates is primarily related to production and transmission fixed charges, specifically new investment in cleaner sources of energy and transmission lines to help reliably meet customers' electric needs as well as forecast cost increases for fuel and purchased power. Partially offsetting these increased costs is a refund of the Wisconsin customers' share of excess funds in the Monticello nuclear generating plant external decommissioning fund. No changes are requested to the capital structure or ROE authorized by the PSCW in the

2010 base rate case.

The major cost components of the requested increase are summarized below:

(Millions of Dollars)	Request
Production and transmission fixed charges	$ 19.3
Fuel and purchased power	12.1
Other	3.5
Monticello nuclear decommissioning fund refund	(5.8)
Total	$ 29.1

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The PSCW held a pre-hearing conference in September 2010 and established the following procedural schedule:

- Staff and intervenor direct testimony due Nov. 5, 2010;
- Rebuttal testimony due Nov. 12, 2010;
- Surrebuttal testimony due Nov. 16, 2010;
- Technical and public hearings scheduled for Nov. 17, 2010; and
- Initial brief due Dec. 6, 2010.

NSP-Wisconsin has requested that the PSCW approve this application to allow new rates to be effective Jan. 1, 2011.

PSCo

Pending and Recently Concluded Regulatory Proceedings — Colorado Public Utilities Commission (CPUC)

Base Rate

2010 Electric Rate Case — In December 2009, the CPUC approved a rate increase of approximately $128.3 million; however, due to the delay in Comanche Unit 3 coming online, the CPUC approved PSCo's proposal to phase in the approved electric rate increase to reflect the actual cost of service. Under the plan, the following increases have or will be implemented:

- A rate increase of $67 million was implemented on Jan. 1, 2010 because of the delay of the in-service date of Comanche Unit 3;
- Base rates were increased to recover $123 million annually, on May 14, 2010 when Comanche Unit 3 went into service, including an additional $2 million of recovery for long-term debt interest in the working capital calculation granted under reconsideration; and
- Base rates will increase to recover approximately $130 million annually on Jan. 1, 2011 to reflect 2011 property taxes.

A second phase of the rate case addressed changes to rate design. The new rates, approved by the CPUC, went into effect on June 1, 2010. In this phase of the proceeding, the CPUC approved tiered summer rates for residential customers and seasonally differentiated rates for other customer classes, which will impact the timing of revenue collection, as compared to the previous rate design, depending on customer response. Seasonal rates are designed to be revenue neutral on an annual basis. However, the quarterly pattern of revenue collection is expected to be different than in the past as seasonal rates are higher in the summer months and lower throughout the remainder of the year.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Adjustment (TCA) Rider — In April 2010, PSCo filed a TCA rider, to adjust the amounts recovered in the rider based on the outcome of the 2010 rate case. The filing reduced rates by $2.3 million, effective June 1, 2010. The new TCA rider reflects actual 13-month average transmission plant in service and year-end transmission construction work in progress (CWIP) account balances for 2009, as compared to the amount of transmission costs included in PSCo's last rate case.

Renewable Energy Credit (REC) Sharing Settlement — In August 2009, PSCo filed an application seeking approval of treatment of margins associated with certain sales of Colorado RECs bundled with energy into California. In January 2010, PSCo, the OCC, the CPUC staff, the Colorado governor's energy office and Western Resource Advocates entered into a unanimous settlement in this case. The settlement establishes a pilot program and defines certain margin splits during this pilot period. The settlement provides that margins would be shared based on the following allocations:

Margin	Customers	PSCo	Carbon Offsets
Less that $10 million	50 %	40 %	10 %
$10 million to $30 million	55	35	10
Greater than $30 million	60	30	10

Amounts designated as carbon offsets are recorded as a regulatory liability until carbon offset-related expenditures are incurred. Carbon offsets are capped at $10 million, with the remaining 10 percent going to customers after the cap is reached. The unanimous settlement also clarified that margins associated with RECs bundled with Colorado energy would be shared 20 percent to PSCo and 80 percent to customers and margins associated with sales of stand-alone RECs without energy would be credited 100 percent to customers. The CPUC approved the settlement in a written order in May 2010.

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

Wholesale Rate Case — In 2009, PSCo filed a request with the FERC to increase electric rates to its firm wholesale customers by $30.7 million based on a 12.5 percent ROE, a 58 percent equity ratio and a rate base of $315 million. During the summer of 2010, PSCo filed blackbox settlements with all of its wholesale customers. The settlements provided for new rates reflecting an electric rate increase of approximately $21.0 million for these customers effective in July 2010. In addition, on Jan. 1, 2011, an additional step rate increase of $1.0 million will be implemented for property taxes associated with Comanche Unit 3. The terms of the settlements provide for lower depreciation expense than requested and for certain capacity costs to be recovered through the fuel clause until those contracts expire. The FERC approved the settlements on Oct. 21, 2010.

SPS

Pending and Recently Concluded Regulatory Proceedings — Public Utility Commission of Texas (PUCT)

Texas Retail Base Rate Case — In May 2010, SPS filed an electric rate case in Texas rate case seeking an annual base rate increase of approximately $62 million. On a net basis, the request seeks to increase customer bills by approximately $53.4 million, or 7 percent. The rate filing is based on a 2009 test year adjusted for known and measurable changes, a requested ROE of 11.35 percent, an electric rate base of $1.031 billion and an equity ratio of 51.0 percent. The following table summarizes the request:

(Millions of Dollars)		Request
Proposed base rate increase	$	62.0
Franchise fee cost recovery		8.7
Nitrogen oxide emission allowances		0.8
Purchased capacity recovery factor		(13.5)
Transmission cost recovery factor		(4.6)
Adjusted rate increase	$	53.4

The filing with the PUCT also includes a request to reconcile SPS' fuel and purchased power costs for calendar years 2008 and 2009. As of Dec. 31, 2009, SPS had a fuel cost under-recovery of approximately $3.3 million.

In September 2010, SPS filed an agreement with the intervening parties to abate, or suspend, the procedural schedule for a 90-day extension in this case. The extension allows time for SPS to receive regulatory approval of the sale of distribution assets to the city of Lubbock, Texas (Lubbock), noted below, and to allow the intervening parties to ascertain the financial impact of the sale. SPS made a filing on Oct. 19, 2010 showing the on-going savings related to the Lubbock sale. As part of the agreement to abate the procedural schedule, the parties agreed that the effective date of implementation of SPS' new rates is expected to be Feb. 16, 2011. This will be accomplished either by establishing interim rates effective on Feb. 16, 2011; or by making the final rates effective retroactive back to Feb. 16, 2011 from the date SPS implements final rates, after the PUCT issues its final order.

The revised the procedural schedule is as follows:

- Intervenor direct testimony due Jan. 18, 2011;
- PUCT staff direct testimony due Jan. 25, 2011;
- PUCT staff and intervenor cross rebuttal testimony due Feb. 1, 2011;
- SPS rebuttal testimony due Feb. 8, 2011; and
- Hearings on Feb. 21, 2011 through March 11, 2011.

Lubbock Electric Distribution Assets — In November 2009, SPS entered into an agreement with Lubbock, in which SPS will sell its electric distribution system assets in Lubbock to Lubbock Power and Light for approximately $87 million. As part of this transaction, SPS will continue to provide the wholesale power to meet the electric load for the customers that SPS currently serves. The wholesale power agreements provide for formula rates that change annually based on the actual cost of service. The formula rate with West Texas Municipal Power Agency (WTMPA) reflects an initial 10.5 percent ROE. All or portions of this transaction are subject to review and approval by the PUCT, the New Mexico Public Regulation Commission (NMPRC) and the FERC. It is anticipated that any resulting gain on the sale of assets will be shared with retail customers in Texas, as determined in the Texas retail base rate case discussed above.

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The FERC accepted the amended WTMPA full-requirements contract in February 2010. SPS filed its application before the PUCT in January 2010 for the approvals related to the sale of distribution assets to Lubbock. In June 2010, an uncontested settlement was filed resolving all issues in the Texas proceeding relating to the transaction. The PUCT approved the uncontested settlement in August 2010.

In June 2010, SPS filed its application in New Mexico for approval of the transaction. Settlement has been reached with all the parties. A decision and order approving the settlement was issued by the NMPRC in October 2010. The transaction is expected to close in late October or early November 2010.

Pending and Recently Concluded Regulatory Proceedings — FERC

Transmission Formula Rate Case — In December 2007, SPS filed a transmission formula rate with the FERC. The FERC accepted the filing, initiated settlement and hearing procedures, and interim rates went into effect on July 6, 2008, subject to refund. An uncontested, partial settlement was reached in September 2009. The settlement, including an 11.27 percent ROE and a future test year, was approved by the FERC in December 2009. The remaining cost allocation of the radial transmission lines issue was resolved by a settlement filed in June 2010, where the expense of the Cap Rock Energy Corporation (Cap Rock) 230 kilovolt (KV) lines was assigned to overall transmission facilities and not directly assigned to Cap Rock. This is subject to a future change in configuration of the 230 KV lines. The radial line settlement was approved by the FERC in August 2010.

Wholesale Rate Complaints — In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer's Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS' rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustment charges to such customers (the complaint). Cap Rock, another full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS' largest retail customer, intervened in the proceeding.

In April 2008, the FERC issued its order on the complaint applied to the remaining non-settling parties. In July 2008, SPS submitted its compliance report to the FERC and calculated the base rate refund for the 18-month period to be $6.1 million and the fuel refund to be $4.4 million. Several wholesale customers protested these calculations. As of Sept. 30, 2010, SPS has accrued an amount it believes is sufficient to cover the estimated refund obligation related to these complaints. The status of various settlements and the applicable regulatory approvals are discussed below. At this time, PNM, which filed a separate complaint, is the only party that has not settled.

Golden Spread Complaint Settlement — SPS reached a settlement with Golden Spread (which included Lyntegar Electric) and Occidental in December 2007 regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. The FERC approved the settlement in April 2008. The PUCT and NMPRC approvals were obtained in the first quarter of 2010 eliminating the potential contingent payments by SPS resulting from an adverse cost assignment decision or a failure to obtain state approvals.

New Mexico Cooperatives' Complaint Settlement — In June 2010, the FERC approved the settlement with Farmers' Electric Cooperative of New Mexico, Lea County Electric Cooperative, Central Valley Electric Cooperative and Roosevelt County Electric Cooperative, and Occidental. The settlement resolves all issues arising from the complaint docket and implements a replacement contract with a formula production rate at 10.5 percent ROE and extended the term of its requirements sale to the four wholesale customers.

The four wholesale customers must reduce their power purchases by 90 to 100 MW in 2012, and implement staged reductions in system average cost power purchases through the term of the agreement, which terminates in May 2026. The settlement made the replacement contract contingent on certain state approvals, which were obtained by

SPS. In the event that all state regulatory approvals had not been received, the settlement included a one time contingent payment of $12 million by SPS to these wholesale customers.

These wholesale customers agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed wholesale power sale. As a result of the FERC approval of the settlement and resolution of the complaint with the New Mexico cooperatives, SPS released previously established reserves of $11.5 million in the second quarter of 2010.

The New Mexico parties and NMPRC staff filed a stipulation to resolve the NMPRC proceeding. The NMPRC issued a final order approving the stipulation in August 2010. The PUCT approved the settlement replacement arrangement in September 2010.

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Cap Rock Complaint Settlement — In July 2010, SPS and Cap Rock filed a settlement agreement with the FERC. Subject to FERC approval of the settlement agreement, SPS will pay Cap Rock $1 million to resolve all remaining base rate and fuel claims against SPS. Cap Rock also agrees that its production base rates will be converted to a formula rate design. The complaint settlement agreement is still pending FERC approval.

7. Commitments and Contingent Liabilities

Except to the extent noted below and in Note 6 to the consolidated financial statements in this Quarterly Report on Form 10-Q, the circumstances set forth in Notes 16, 17 and 18 to the consolidated financial statements included in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009, 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.

Commitments

Variable Interest Entities — Effective Jan. 1, 2010, Xcel Energy adopted new guidance on consolidation of variable interest entities contained in ASC 810 Consolidation. The guidance requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an entity is a variable interest entity and whether an enterprise is a variable interest entity's primary beneficiary.

Purchased Power Agreements — The utility subsidiaries of Xcel Energy have entered into agreements with other utilities and energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance or during outages, and meet operating reserve obligations.

NSP-Minnesota, PSCo and SPS have various pay-for-performance contracts with expiration dates through the year 2034. In general, these contracts provide for energy payments based on actual power taken under the contracts as well as capacity payments. Capacity payments are typically contingent on the independent power producing entity meeting certain contract obligations, including plant availability requirements. Certain contractual payments are adjusted based on market indices; however, the effects of price adjustments are mitigated through purchased energy cost recovery mechanisms.

Xcel Energy purchases power from independent power producing entities that own natural gas or biomass fueled power plants. Under certain purchased power agreements with these entities, Xcel Energy is required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which Xcel Energy procures the natural gas required to produce the energy that Xcel Energy purchases. These purchased power agreements have been determined by Xcel Energy to create variable interests in the independent power producing entities; therefore, certain independent power producing entities are variable interest entities.

Xcel Energy is not subject to risk of loss from the operations of these entities, and no significant financial support has been, or is in the future required to be provided other than contractual payments for energy and capacity set forth in purchased power agreements.

Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M, historical and estimated future fuel and electricity prices, and financing activities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. As of Sept. 30, 2010 and Dec. 31, 2009, Xcel Energy had approximately 5,012 MW of capacity under long-term purchased power agreements with entities that have been determined to be variable interest entities.

Fuel Contracts — SPS purchases all of its coal requirements for its Harrington and Tolk electric generating stations from TUCO, Inc. (TUCO) under contracts for those facilities that expire in 2016 and 2017, respectively. TUCO arranges for the purchase, receiving, transporting, unloading, handling, crushing, weighing, and delivery of coal to meet SPS' requirements. TUCO is responsible for negotiating and administering contracts with coal suppliers, transporters and handlers.

No significant financial support has been, or is in the future, required to be provided to TUCO by SPS, other than contractual payments for delivered coal. However, the fuel contracts have been determined to create a variable interest in TUCO due to SPS' reimbursement of certain fuel procurement costs, and therefore TUCO is a variable interest entity. SPS has concluded that it is not the primary beneficiary of TUCO because SPS does not have the power to direct the activities that most significantly impact TUCO's economic performance.

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Low-Income Housing Limited Partnerships — Eloigne Company (Eloigne) and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. These limited partnerships are designed to qualify for low-income housing tax credits, and Eloigne and NSP-Wisconsin generally receive a larger allocation of the tax credits than the general partners at inception of the arrangements. Xcel Energy has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy consolidates these limited partnerships in its consolidated financial statements.

Equity financing for these entities has been provided by Eloigne and NSP-Wisconsin and the general partner of each limited partnership, and Xcel Energy's risk of loss is limited to its capital contributions, adjusted for any distributions and its share of undistributed profits and losses; no significant additional financial support has been, or is in the future, required to be provided to the limited partnerships by Eloigne or NSP-Wisconsin. Mortgage-backed debt typically comprises the majority of the financing at inception of each limited partnership and is paid over the life of the limited partnership arrangement. Obligations of the limited partnerships are generally secured by the low-income housing properties of each limited partnership, and the creditors of each limited partnership have no significant recourse to Xcel Energy or its subsidiaries. Likewise, the assets of the limited partnerships may only be used to settle obligations of the limited partnerships, and not those of Xcel Energy or its subsidiaries.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Current assets	$ 3,527	$ 3,674
Property, plant and equipment, net	100,144	103,552
Other noncurrent assets	8,355	7,577
Total assets	$ 112,026	$ 114,803
Current liabilities	$ 11,832	$ 12,315
Mortgages and other long-term debt payable	54,524	54,927
Other noncurrent liabilities	8,344	8,250
Total liabilities	$ 74,700	$ 75,492

Environmental Contingencies

Xcel Energy and its subsidiaries have been, or are currently, involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties (PRPs) and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation — Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by Xcel Energy subsidiaries, predecessors, or other entities; and third-party sites, such as landfills, for which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At Sept. 30, 2010 and Dec. 31, 2009, the liability for the cost of remediating these sites was estimated to be $101.9 million and $102.1 million, respectively, of which $5.3 million and $6.3 million, respectively, was considered to be a current liability.

Manufactured Gas Plant Sites

Ashland MGP Site — NSP-Wisconsin has been named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill; and an area of Lake Superior's Chequamegon Bay adjoining the park.

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In September 2002, the Ashland site was placed on the National Priorities List. In 2009, the Environmental Protection Agency (EPA) issued its proposed remedial action plan (PRAP). NSP-Wisconsin submitted comments to the EPA in response to the PRAP, and indicated that it had serious concerns about the cleanup approach proposed by the EPA. The EPA issued its Record of Decision (ROD) on Sept. 30, 2010, which documents the remedy that the EPA has selected for the cleanup of the site. The EPA has estimated the cost for its selected cleanup is between $84 million and $98 million. NSP-Wisconsin continues to have concerns over the cleanup approach selected by the EPA. It is anticipated that the EPA will issue special notice letters to several PRPs, including NSP-Wisconsin, by Dec. 1, 2010, and in those letters, the EPA will invite the PRPs to participate in negotiations with the EPA to conduct or pay for all, or a portion, of the future cleanup work at the site.

NSP-Wisconsin's potential liability, the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable until after the EPA issues special notice letters and engages in negotiations with the PRPs at the site. 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. NSP-Wisconsin has recorded a liability of $97.5 million based upon the remediation and design costs estimated by the ROD, together with estimated outside legal and consultant costs.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until 2011.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

In addition to potential liability for remediation, NSP-Wisconsin may also have potential liability for natural resource damages at the Ashland site. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Third Party and Other Environmental Site Remediation

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation (ARO). See additional discussion of AROs in Note 17 to the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2009. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA Greenhouse Gas (GHG) Rulemaking — In December 2009, in response to the U.S. Supreme Court's decision in Massachusetts v. EPA, 549 U.S. 497 (2007), the EPA issued its "endangerment" finding that GHG emissions endanger public health and welfare and that emissions from motor vehicles contribute to the GHGs in the atmosphere. The EPA has promulgated permit requirements for GHGs for large new and modified stationary sources, such as power plants. These regulations will become applicable in 2011.

Clean Air Interstate Rule (CAIR) — In March 2005, the EPA issued the CAIR to further regulate sulfur dioxide (SO2) and nitrogen oxide (NOx) emissions. The objective of CAIR is to cap emissions of SO2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy's service territory. In 2008, the U.S. Court of Appeals for the District of Columbia vacated and remanded CAIR.

In July 2010, the EPA issued the proposed Clean Air Transport Rule (CATR), which would replace CAIR by requiring SO2 and NOx reductions in 31 states and the District of Columbia. The EPA is proposing to reduce these emissions through federal implementation plans for each affected state. The EPA's preferred approach would set emission limits for each state and allow limited interstate emissions trading. As proposed, CATR will impact Minnesota and Wisconsin for annual SO2 and NOx emissions, and Texas in the form of ozone season NOx emission allowances. Xcel Energy is analyzing the proposed rule to determine whether emission reductions are needed from facilities in these affected states. Until CATR becomes final, Xcel Energy will continue activities to support CAIR compliance.

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CAIR – SPS
Under CAIR's cap and trade structure, SPS can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. The remaining scheduled capital investments for NOx controls in the SPS region are estimated at $16.4 million. For 2009, the NOx allowance compliance costs were $1.7 million. The estimated NOx allowance cost for 2010 is $0.5 million. Annual purchases of SO2 allowances are estimated up to $4.5 million each year, beginning in 2013, for phase I. If CATR is implemented as proposed then no SO2 allowances would be purchased since CATR replaces CAIR. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

CAIR – NSP-Wisconsin and NSP-Minnesota
For 2009, the NOx allowance costs for NSP-Wisconsin were $0.5 million. The estimated NOx allowance cost for 2010 is $0.2 million. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates. In November 2009, the EPA published a rule staying the effectiveness of CAIR in Minnesota effective in December 2009. Cost estimates are therefore not included at this time for NSP-Minnesota.

Clean Air Mercury Rule (CAMR) — In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the U.S. Court of Appeals for the District of Columbia vacated the CAMR, which impacted federal CAMR requirements, but not necessarily state-only mercury legislation and rules. The EPA has agreed to finalize Maximum Achievable Control Technology (MACT) emission standards for all hazardous air pollutants from electric utility steam generating units by November 2011 to replace the CAMR. Xcel Energy anticipates that the EPA will require affected facilities to demonstrate compliance within three to five years.

Colorado Mercury Regulation — Colorado's mercury regulations require mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and other specified units by 2014. The expected cost estimate for the Pawnee Generating Station is $2.3 million for capital costs with an annual estimate of $1.4 million for sorbent expense. PSCo has evaluated the Colorado mercury control requirements for its other units in Colorado and believes that, under the current regulations, no further controls will be required other than the planned controls at the Pawnee Generating Station.

Minnesota Mercury Legislation — In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For NSP-Minnesota, the Act covers units at the A.S. King and Sherco generating facilities. NSP-Minnesota installed and is operating and maintaining continuous mercury emission monitoring systems at these generating facilities.

In November 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A.S. King mercury emission reduction plans. A sorbent injection control system was installed at Sherco Unit 3 in December 2009, with installation at A.S. King scheduled for December 2010. In November 2009, the MPUC authorized NSP-Minnesota to collect approximately $3.5 million from customers through a mercury rider in 2010.

In December 2009, NSP-Minnesota filed its mercury control plan at Sherco Units 1 and 2 with the MPUC and the Minnesota Pollution Control Agency (MPCA). In June 2010, the MPCA filed its comments on the Sherco Unit 1 and 2 mercury plan and believes the plan to be appropriate under the Act. The MPUC is expected to either approve or disapprove the plan by Dec. 15, 2010. Assuming that the plan is approved, NSP-Minnesota expects to file for recovery of the costs to implement the plan through the mercury cost recovery rider.

Regional Haze Rules — In June 2005, the EPA finalized amendments to its regional haze rules regarding provisions that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements. States are required to identify the facilities that will have to reduce SO2, NOx and particulate matter emissions under BART and then set BART emissions limits for those facilities.

PSCo
In May 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate, install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. The Colorado Air Pollution Control Division (CAPCD) is currently analyzing what types of NOx controls may be necessary to meet BART and reasonable progress goals for Colorado's Class I areas. The CAPCD has indicated that it expects to submit a Regional Haze BART/Reasonable Further Progress state implementation plan (SIP) to the EPA in early 2011. PSCo anticipates that for those plants included in the Colorado Clean Air-Clean Jobs Act's (CACJA) emission reduction plan, the plan will satisfy regional haze requirements. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2012 and 2017.

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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. Four PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege that the Colorado BART rule is inadequate to satisfy the Clean Air Act (CAA) mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota
NSP-Minnesota submitted its BART alternatives analysis for Sherco Units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. The MPCA completed their BART determination and proposed SO2 and NOx limits in the draft SIP that are equivalent to the reductions made under CAIR.

In October 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota’s Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to visibility impairment and, if so, whether the level of controls proposed by MPCA is appropriate.

The MPCA determined that this certification does not alter the proposed SIP. The SIP proposes BART controls for the Sherco generating facilities that are designed to improve visibility in the national parks, but does not require Selective Catalytic Reduction (SCR) on Units 1 and 2. The MPCA concluded that the minor visibility benefits derived from SCR do not outweigh the substantial costs. In December 2009, the MPCA Citizens Board approved the SIP, which has been submitted to the EPA for approval. The EPA is expected to complete its review of the SIP, as well as the Sherco Units 1 and 2 BART determination before the end of 2010.

Federal Clean Water Act — The federal Clean Water Act (CWA) requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA challenging the phase II rulemaking. In April 2009, the U.S. Supreme Court issued a decision in Entergy Corp. v. Riverkeeper, Inc., concluding that the EPA can consider a cost benefit analysis when establishing BTA. The decision overturned only one aspect of the Court of Appeals’ earlier opinion, and gives the EPA the discretion to consider costs and benefits when it reconsiders its phase II rules. Until the EPA fully responds, the rule’s compliance requirements and associated deadlines will remain unknown. As such, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

As part of NSP-Minnesota’s 2009 CWA permit renewal for the Black Dog plant, the MPCA required that the plant submit a plan for compliance with the CWA. The compliance plan was submitted for MPCA review and approval in April 2010. The MPCA is currently reviewing the proposal in consultation with the EPA. Xcel Energy anticipates approval of the plan by the end of 2010.

Proposed Coal Ash Regulation — In June 2010, the EPA published a proposed rule seeking comment on whether to regulate coal combustion byproducts (often referred to as coal ash) as a special waste (subject to many of the requirements for hazardous waste) or as a solid (nonhazardous) waste. Coal ash is currently exempt from hazardous waste regulation. The EPA's proposal would result in more comprehensive and expensive requirements related to management and disposal of coal ash. The EPA has extended the public comment period on the proposed rule until Nov. 19, 2010. The EPA is also seeking comment on what regulations are appropriate for the beneficial reuse of coal ash. The timing, scope and potential cost of any final rule that might be implemented are not determinable at this time.

PSCo Notice of Violation (NOV) — In July 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Station in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid to late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

Cunningham Draft Compliance Order — On Feb. 18, 2010, SPS received a draft compliance order from the New Mexico Environment Department (NMED) for Cunningham Station. In the draft order, NMED alleges that Cunningham exceeded its permit limits for NOx on 7,336 occasions and failed to report these exceedances as required by its permit. The draft order included a proposed penalty of $16.1 million. On Sept. 28, 2010, the NMED issued a final compliance order, which reduced the alleged NOx exceedances to approximately 4,000 occasions and the proposed penalty to $7.6 million. SPS intends to request an administrative hearing to contest the order.

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Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy's financial position and results of operations.

Gas Trading Litigation

e prime, inc. (e prime) is a wholly owned subsidiary of Xcel Energy. e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Thirteen lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin, in one instance); alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP-Wisconsin deny these allegations, believe they are without merit and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas-trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the U.S. District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned Texas-Ohio Energy vs. CenterPoint Energy et al. The other twelve cases arising out of the same or similar set of facts are captioned Fairhaven Power Company vs. EnCana Corporation et al.; Ableman Art Glass vs. EnCana Corporation et al.; Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. et al.; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al.; Learjet, Inc. vs. e prime and Xcel Energy Inc et al.; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al.; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al.; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. et al.; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al.; NewPage Wisconsin System Inc vs. e prime, Xcel Energy, NSP-Wisconsin et al. and Heartland Regional Medical Center vs. e prime, Xcel Energy et al. Many of these cases involve multiple defendants and have been transferred to Judge Phillip Pro of the U.S. District Court in Nevada, who is the judge assigned to the Western Area Wholesale Natural Gas Antitrust Litigation.

e prime and some other defendants were dismissed from the Breckenridge Brewery lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

No trial dates have been set for any of these lawsuits. In 2009, the parties reached a settlement agreement in the Abelman Art Glass, Ever Bloom, Fairhaven Power Company, Texas-Ohio Energy, and Utility Savings and Refund Services cases. The terms of the settlement did not have a material financial effect upon Xcel Energy. Discovery in most of the remaining cases was completed by Dec. 5, 2009. Trial for all cases venued in Nevada will likely be set for 2011 if pending motions to dismiss are not granted.

In November 2007, the Missouri Public Service Commission case was remanded to Missouri state court. On Jan. 13, 2009, the Missouri state court granted defendants' motion to dismiss plaintiff's complaint for lack of standing. Plaintiffs filed an appeal and on Dec. 8, 2009, the Missouri Court of Appeals affirmed the dismissal. The Missouri Supreme Court subsequently granted plaintiff's motion for transfer but subsequently returned the matter to the Missouri Court of Appeals which simply reaffirmed its earlier dismissal of the complaint.

In March 2009, Newpage Wisconsin System Inc. commenced a lawsuit in state court in Wood County, Wis. The allegations are substantially similar to Arandell and name several of the same defendants, including Xcel Energy, e prime and NSP-Wisconsin. In September 2009, Plaintiffs moved to consolidate the Newpage and Arandell matters. In June 2010, the court denied defendants' motions to dismiss the Newpage lawsuit on statute of limitations grounds and granted the motion to consolidate New Page and Arandell.

Environmental Litigation

State of Connecticut vs. Xcel Energy Inc. et al. — In 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO2) emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO2 emitted by each company is a public nuisance. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO2 emissions. On Sept. 19, 2005, the court granted a motion to dismiss on constitutional grounds. On appeal in September 2009, the U.S. Court of Appeals for the Second Circuit reversed the lower court decision. In August 2010, defendants filed a petition for review with the U.S. Supreme Court.

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Comer vs. Xcel Energy Inc. et al. — In 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants' CO_2 emissions "were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina." Plaintiffs allege negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. Plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Fifth Circuit. In October 2009, the U.S. Court of Appeals for the Fifth Circuit reversed the district court decision, in part, concluding that the plaintiffs pleaded sufficient facts to overcome the constitutional challenges that formed the basis for dismissal by the district court. A subsequent petition by defendants, including Xcel Energy, for en banc review was granted. On May 28, 2010, the U.S. Court of Appeals for the Fifth Circuit ruled that it lacked an en banc quorum of nine active members to hear the case. It dismissed the appeal, which resulted in the reinstatement of the district court's opinion dismissing the case. Plaintiffs subsequently filed with the U.S. Supreme Court a writ of mandamus, which is a procedure requesting the court to order the Fifth Circuit to review plaintiffs' earlier appeal. Defendants intend to oppose this request.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utilities, oil, gas and coal companies. 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 on June 30, 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. All briefs related to this appeal have been filed. It is unknown when the Ninth Circuit will render a final opinion.

Comanche Unit 3 CAA Lawsuit — In July 2009, WildEarth Guardians (WEG) filed a lawsuit in the U.S. District Court in Colorado against PSCo alleging that PSCo violated the CAA by constructing Comanche Unit 3 without a final MACT determination from the Colorado Department of Public Health and Environment, Air Pollution Control Division (APCD). PSCo disputes these claims and filed a motion to dismiss the suit. Comanche Unit 3 was constructed with state-of-the-art emission controls and pursuant to a valid air permit issued by the APCD. In January 2010, WEG sought to enjoin PSCo from constructing, modifying, or operating Comanche Unit 3 prior to receiving a final MACT determination. The court denied WEG's request for a temporary restraining order on Jan. 26, 2010. In March 2010, the court partially granted and partially denied PSCo's motion to dismiss. The court requested additional briefing on certain issues related to the MACT determination. Briefing has now been completed, and the court is expected to issue a final ruling in due course.

United States vs. Xcel Energy Inc. et al. — In June 2010, the U.S. Department of Justice and the EPA filed a complaint in the U.S. District Court in Minnesota against Xcel Energy, alleging that Xcel Energy has failed to fully respond to certain information requests issued by the EPA. Over the last ten years, Xcel Energy has responded to numerous information requests from the EPA pursuant to section 114 of the CAA. The requests focused on past projects undertaken at Xcel Energy's Sherco and Black Dog plants to determine whether these projects were carried out in compliance with the NSR requirements. Xcel Energy has complied with these requests and produced thousands of pages of documents. In June 2009, the EPA issued a supplemental information request which, among other things, asked for ten years of prospective capital project documentation related to projects that may be undertaken in the future at the plants. Xcel Energy believed that the request for future project information exceeded the EPA's CAA authority and filed a motion to dismiss the lawsuit. The EPA filed a motion for preliminary injunction in which it narrowed its request to two years of prospective capital project documentation. On Sept. 27, 2010, the court denied Xcel Energy's motion to dismiss and ruled that two years of future documentation is reasonable, but rejected the request for ten years of documentation. The court granted the EPA's motion for a preliminary injunction and ruled that a limited set of responsive documents be produced. Xcel Energy is complying with this order.

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy — In 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota’s distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. In December 2008, the Court of Appeals issued a decision ordering dismissal of plaintiffs’ claims for injunctive relief, but otherwise rejecting NSP-Minnesota’s contentions and ordering the matter remanded for trial. The Minnesota Supreme Court subsequently granted NSP-Minnesota’s petition for further review and heard oral arguments in December 2009. It is uncertain when the Minnesota Supreme Court will render a decision.

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Qwest vs. Xcel Energy Inc. — In 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Colorado state court in Denver. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. In April 2009, the Colorado Court of Appeals affirmed the jury verdict insofar as it relates to claims asserted by Qwest against PSCo. Qwest filed a petition for rehearing with the Colorado Supreme Court in June 2009. In February 2010, the Colorado Supreme Court agreed to review the Court of Appeals' decision as to the punitive damages issue but will not review the Court of Appeals' decision as it relates to PSCo. Oral arguments are set for December 2010. It is unknown when the Colorado Supreme Court will render a decision.

MGP Insurance Coverage Litigation — In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and La Crosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin's insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. In July of 2007, the Minnesota trial court granted defendant's motion for summary judgment, which was affirmed on appeal in August 2009. Pursuant to defendants' motion, the Wisconsin action was dismissed in March 2010. In April 2010, NSP-Wisconsin appealed this decision to the Wisconsin Court of Appeals. It is unknown when the Wisconsin Court of Appeals will render a decision.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions. NSP-Wisconsin has also reached settlements in principle with Ranger Insurance Company, TIG Insurance Company, Royal Indemnity Company and Globe Indemnity Company.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy's consolidated financial statements.

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy's (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. In September 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE's motion for reconsideration. In February 2008, the DOE filed an appeal to the U.S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. It is uncertain when the Court will issue a decision. Results of the judgment will not be recorded in earnings until the appeal, regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the U.S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit will claim damages for the period Jan. 1, 2005 through Dec. 31, 2008, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. Per the court's scheduling order, NSP-Minnesota believes that it has suffered damages in excess of $250 million. The DOE claims NSP-Minnesota is entitled to at most approximately $55 million. Trial is expected to take place in early 2011.

Mallon vs. Xcel Energy Inc. — In August 2007, Xcel Energy, PSCo and PSRI (Plaintiffs) commenced a lawsuit in Colorado state court against Theodore Mallon (Mallon) and TransFinancial Corporation seeking damages for, among other things, breach of contract and breach of fiduciary duties associated with the sale of COLI policies. In May 2008, Plaintiffs filed an amended complaint that, among other things, adds Provident as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. In November 2009, Plaintiffs reached a settlement with Mallon and TransFinancial Corporation, where Mallon agreed to pay Plaintiffs a specified amount of money and the parties agreed to mutually release each other from all claims.

In July 2010, Plaintiffs entered into a settlement agreement with Provident and Reassure America Life Insurance Company. Under the terms of the settlement, Provident paid Plaintiffs $25 million. Xcel Energy recorded this settlement of $25 million in the third quarter of 2010. The $25 million proceeds are not subject to income taxes.

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Cabin Creek Hydro Generating Station Accident — In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo's Cabin Creek Hydro Generating Station (CCH) near Georgetown, Colo. A fire occurred inside a pipe used to deliver water from a reservoir to the hydro facility. Five RPI employees were unable to exit the pipe and rescue crews confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U.S. Chemical Safety Board (CSB) and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for 22 serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008, the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17, 2008. The Court ordered this proceeding stayed until March 3, 2009 and has subsequently extended the stay until the criminal proceedings have concluded.

A lawsuit was filed in Colorado state court in Denver on behalf of four of the deceased workers and four of the injured workers (Foster, et. al. v. PSCo, et. al.). PSCo and Xcel Energy were named as defendants in that case, along with RPI Coatings and related companies and the two other contractors who also performed work in connection with the relining project at Cabin Creek. A second lawsuit (Ledbetter et. al vs. PSCo et. al) was also filed in Colorado state court in Denver on behalf of three employees allegedly injured in the accident. A third lawsuit was filed on behalf of one of the deceased RPI workers in the California state court (Aguirre v. RPI, et. al.), naming PSCo, RPI, and the two other contractors as defendants. The court subsequently dismissed the Aguirre lawsuit. Settlements were subsequently reached in all three lawsuits. These confidential settlements did not have a material effect on the financial statements of Xcel Energy or its subsidiaries.

On Aug. 28, 2009, the U.S. Government announced that Xcel Energy and PSCo have been charged with five misdemeanor counts in federal court in Colorado for violation of an OSHA regulation related to the accident at Cabin Creek in October 2007. RPI Coatings, the contractor performing the work at the plant, and two individuals employed by RPI have also been indicted. On Sept. 22, 2009, both Xcel Energy and PSCo entered a not guilty plea, and both will vigorously defend against these charges. In December 2009, Xcel Energy and PSCo filed two separate motions to dismiss. On March 29, 2010, the court issued an order denying both motions. No trial date has yet been set.

In August 2010, the CSB issued a report related to its investigation of the CCH accident. The report contains several findings and recommendations, some of which pertain to PSCo. Consistent with its delegated authority, the CSB investigation did not result in the issuance of any fines or penalties. PSCo intends to respond to the CSB concerning its recommendations in due course.

Stone & Webster, Inc. vs. PSCo — In July 2009, Stone & Webster, Inc. (Shaw) filed a complaint against PSCo in State District Court in Denver, Colo. for damages allegedly arising out of its construction work on the Comanche Unit 3 coal-fired plant. Shaw, a contractor retained to perform certain engineering, procurement and construction work on Comanche Unit 3, alleges, among other things, that PSCo mismanaged the construction of Comanche Unit 3. Shaw further claims that this alleged mismanagement caused delays and damages. The complaint also alleges that Xcel Energy and related entities guaranteed Shaw $10 million in future profits under the terms of a 2003 settlement agreement. Shaw alleges that it will not receive the $10 million to which it is entitled. Accordingly, Shaw seeks an amount up to $10 million relating to the 2003 settlement agreement. In total, Shaw seeks approximately $144 million in damages.

PSCo denies these allegations and believes the claims are without merit. PSCo filed an answer and counterclaim in August 2009, denying the allegations in the complaint and alleging that Shaw has failed to discharge its contractual obligations and has caused delays, and that PSCo is entitled to liquidated damages and excess costs incurred. In total, PSCo is seeking approximately $82 million in damages. In June 2010, PSCo exercised its contractual right to draw on Shaw's letter of credit in the total amount of approximately $29.6 million. In September 2010, Shaw filed a second lawsuit related to PSCo's decision to draw on the letter of credit. PSCo denies the merits of this claim.

Trial commenced on Oct. 18, 2010 and is expected to last approximately four weeks. The trial will address only those issues raised in the first complaint and will not include Shaw's claim asserted in the second lawsuit related to the letter of credit.

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Fru-Con Construction Corporation (Fru-Con) vs. Utility Engineering Corporation (UE) et al. — In March 2005, Fru-Con commenced a lawsuit in U.S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con's complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE's motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

Connie DeWeese vs. PSCo — In November 2008, there was an explosion in Pueblo, Colo., which destroyed a tavern and a neighboring store. The explosion killed one person and injured seven people. The Pueblo Fire Department and the Federal Bureau of Alcohol, Tobacco and Firearms have determined a natural gas leak from a pipeline under the street led to the explosion. In February 2010, a wrongful death/personal injury lawsuit was filed in Colorado District Court in Pueblo, Colorado against PSCo and the City of Pueblo by several parties that were allegedly injured, as a result of this explosion. The plaintiffs are also alleging economic and noneconomic damages. The lawsuit alleges that the accident occurred as a result of PSCo's negligence. A related lawsuit was filed in March 2010 by Seneca Insurance Company, which insured Branch Inn, LLC and Branch Inn Enterprises, LLC. The Plaintiffs are alleging destruction of the building and disruption of the business. Both lawsuits allege that the accident occurred as a result of PSCo's negligence. PSCo denies liability for this accident. The cases have been consolidated. In June 2010, the court granted, in part, PSCo's motion to dismiss certain of plaintiffs' claims related to, among other things, strict liability. In July 2010, a third related lawsuit was filed by Truck Insurance Exchange against PSCo and the City of Pueblo to recover damages allegedly paid by the plaintiff insurance company to its insured as a result of the explosion. In September 2010, six plaintiffs filed a fourth lawsuit, Vigil vs. Xcel Energy, in Hennepin County District Court in Minneapolis, Minn., alleging personal injury and property damage as a result of the November 2008 explosion. In response, a motion has been filed to dismiss the lawsuit for improper venue and for naming the wrong party defendant.

8. Short-Term Borrowings and Other Financing Instruments

Commercial Paper — The following table presents commercial paper outstanding for Xcel Energy:

(Millions of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Commercial paper outstanding	$ 40	$ 459
Weighted average interest rate	0.33 %	0.36 %
Commercial paper borrowing limit	$ 2,177	$ 2,177

Credit Facility Bank Borrowings — Xcel Energy and its subsidiaries had no credit facility bank borrowings at Sept. 30, 2010 and Dec. 31, 2009.

Money Pool — Xcel Energy and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings from the utilities between each other. The holding company 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 the holding company. The money pool investments and borrowings are eliminated upon consolidation.

9. Long-Term Borrowings and Other Financing Instruments

In February 2010, SPS redeemed its $25.0 million pollution control obligations, securing pollution control revenue bonds, due July 1, 2016.

In May 2010, Xcel Energy issued $550 million of 4.70 percent unsecured senior notes, due May 15, 2020. Xcel Energy added the net proceeds from the sale of the notes to its general funds and used the proceeds to repay commercial paper and fund equity investments in its utility subsidiaries.

In August 2010, NSP-Minnesota issued $250 million of 1.95 percent first mortgage bonds, due Aug. 15, 2015 and $250 million of 4.85 percent first mortgage bonds, due Aug. 15, 2040. NSP-Minnesota added the net proceeds from the sale of the bonds to its general funds and applied a portion of the proceeds to the repayment of short-term debt, including short-term debt incurred to fund the repayment at maturity of $175 million of 4.75 percent first mortgage bonds due Aug. 1, 2010. The balance of the net proceeds was used for general corporate purposes, including the funding of capital expenditures.

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10. Derivative Instruments and Fair Value Measurements

Xcel Energy and its utility subsidiaries enter into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather.

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

Interest Rate Derivatives — Xcel Energy and its utility subsidiaries enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Sept. 30, 2010, accumulated other comprehensive income (OCI) related to interest rate derivatives included $0.7 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

Commodity Derivatives — Xcel Energy's utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices in their electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At Sept. 30, 2010, Xcel Energy had various vehicle fuel related contracts designated as cash flow hedges extending through December 2012. Xcel Energy's utility subsidiaries also enter 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, 2010.

At Sept. 30, 2010, accumulated OCI related to commodity derivative cash flow hedges included $0.7 million of net losses expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy's utility subsidiaries enter into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving their electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in income, subject to applicable customer margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options, and financial transmission rights (FTRs) at Sept. 30, 2010 and Dec. 31, 2009:

(Amounts in Thousands) (a)(b)	Sept. 30, 2010	Dec. 31, 2009
Megawatt hours (MWh) of electricity	58,879	37,932
MMBtu of natural gas	95,443	57,181
Gallons of vehicle fuel	1,195	3,580

(a) Amounts are not reflective of net positions in the underlying commodities.
(b) Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

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

(Thousands of Dollars)	Three Months Ended Sept. 30, 2010	2009
Accumulated other comprehensive loss related to cash flow hedges at July 1	$ (9,590)	$ (9,782)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	35	(6,589)
After-tax net realized losses on derivative transactions reclassified into earnings	749	1,032
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$ (8,806)	$ (15,339)

(Thousands of Dollars)	Nine Months Ended Sept. 30, 2010	2009
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (6,435)	$ (13,113)
After-tax net unrealized losses related to derivatives accounted for as hedges	(4,350)	(5,770)
After-tax net realized losses on derivative transactions reclassified into earnings	1,979	3,544
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$ (8,806)	$ (15,339)

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2010 and Sept. 30, 2009. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2010 and Sept. 30, 2009, respectively, on OCI, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	
Derivatives designated as cash flow hedges:					
Interest rate	$-	$-	$344 (a)	$-	$ -
Vehicle fuel and other commodity	61	-	933 (e)	-	-
Total	$61	$-	$1,277	$-	$ -
Other derivative instruments:					
Trading commodity	$-	$-	$-	$-	$ 4,320 (b)
Electric commodity	-	6,568	-	(8,259)(c)	-
Natural gas commodity	-	(65,303)	-	925 (d)	-
Total	$-	$(58,735)	$-	$(7,334)	$ 4,320

	Nine Months Ended Sept. 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	
Derivatives designated as cash flow hedges:					
Interest rate	$(7,210)	$-	$763 (a)	$-	$ -
Vehicle fuel and other commodity	(261)	-	2,626 (e)	-	-
Total	$(7,471)	$-	$3,389	$-	$ -
Other derivative instruments:					
Trading commodity	$-	$-	$-	$-	$ 9,925 (b)
Electric commodity	-	(3,014)	-	(13,097)(c)	-
Natural gas commodity	-	(106,009)	-	5,632 (d)	-
Other	-	-	-	-	135 (b)
Total	$-	$(109,023)	$-	$(7,465)	$ 10,060

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	Three Months Ended Sept. 30, 2009				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	
Derivatives designated as cash flow hedges:					
Interest rate	$(10,846)	$-	$291 (a)	$-	$-
Natural gas commodity	-	1,457	-	202 (d)	-
Vehicle fuel and other commodity	(304)	-	1,426 (e)	-	-
Total	$(11,150)	$1,457	$1,717	$202	$-
Other derivative instruments:					
Interest rate	$-	$-	$-	$-	$(242)(a)
Trading commodity	-	-	-	-	2,850 (b)
Electric commodity	-	(8,012)	-	1,284 (c)	-
Natural gas commodity	-	46,700	-	1,325 (d)	-
Total	$-	$38,688	$-	$2,609	$2,608

	Nine Months Ended Sept. 30, 2009				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	
Derivatives designated as cash flow hedges:					
Interest rate	$(11,425)	$-	$834 (a)	$-	$-
Electric commodity	-	(18,599)	-	(4,755)(c)	-
Natural gas commodity	-	(15,830)	-	78,488 (d)	(30,241)(d)
Vehicle fuel and other commodity	1,610	-	5,019 (e)	-	-
Total	$(9,815)	$(34,429)	$5,853	$73,733	$(30,241)
Other derivative instruments:					
Interest rate	$-	$-	$-	$-	$1,766 (a)
Trading commodity	-	-	-	-	6,918 (b)
Electric commodity	-	35,329	-	899 (c)	-
Natural gas commodity	-	37,535	-	1,340 (d)	-
Other	-	-	-	-	200 (b)
Total	$-	$72,864	$-	$2,239	$8,884

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are shared with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c) Recorded to electric fuel and purchased power; these derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d) Recorded to cost of natural gas sold and transported; these derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Recorded to other O&M expenses.

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Credit Related Contingent Features — Contract provisions of the derivative instruments that the utility subsidiaries enter into may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of PSCo were downgraded below investment grade, contracts underlying $7.7 million and $0.6 million of derivative instruments in a net liability position at Sept. 30, 2010 and Dec. 31, 2009, respectively, would have required Xcel Energy to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $7.7 million and $3.4 million, respectively. At Sept. 30, 2010 and Dec. 31, 2009, there was no collateral posted on these specific contracts.

Certain of the utility subsidiaries' 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's utility subsidiaries had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2010 and Dec. 31, 2009.

Fair Value Measurements

ASC 820 Fair Value Measurements and Disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported 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 reported 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 reported date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

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Recurring Fair Value Measurements

The following table presents for each of the hierarchy levels, Xcel Energy’s assets and liabilities that are measured at fair value on a recurring basis at Sept. 30, 2010:

	Sept. 30, 2010					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (c)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$57	$-	$57	$ (57)	$-
Other derivative instruments:						
Trading commodity	3,928	34,336	2	38,266	(23,412)	14,854
Electric commodity	-	-	5,282	5,282	(1,130)	4,152
Natural gas commodity	-	24	-	24	(24)	-
Total current derivative assets	$3,928	$34,417	$5,284	$43,629	$ (24,623)	19,006
Purchased power agreements (b)						46,567
Current derivative instruments valuation						$65,573
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$103	$-	$103	$ -	$103
Other derivative instruments:						
Trading commodity	-	43,899	-	43,899	(8,024)	35,875
Natural gas commodity	-	10	-	10	(1)	9
Total noncurrent derivative assets	$-	$44,012	$-	$44,012	$ (8,025)	35,987
Purchased power agreements (b)						225,761
Noncurrent derivative instruments valuation						$261,748
Other recurring fair value assets						
Cash equivalents	$-	$65,000	$-	$65,000	$ -	$65,000
Nuclear decommissioning fund: (a)						
Cash equivalents	-	42,117	-	42,117	-	42,117
Commingled funds	-	114,845	-	114,845	-	114,845
International equity funds	-	57,155	-	57,155	-	57,155
Debt securities:						
Government securities	-	209,806	-	209,806	-	209,806

US corporate bonds	-	317,295	-	317,295	-	317,295
Foreign securities	-	2,258	-	2,258	-	2,258
Municipal bonds	-	81,759	-	81,759	-	81,759
Asset-backed securities	-	-	34,494	34,494	-	34,494
Mortgage-backed securities	-	-	64,396	64,396	-	64,396
Equity securities (common stock)	390,993	-	-	390,993	-	390,993
Total nuclear decommissioning fund	$390,993	$825,235	$98,890	$1,315,118	$ -	$1,315,118

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	Sept. 30, 2010					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (c)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$805	$-	$805	$ (57)	$748
Other derivative instruments:						
Trading commodity	3,064	30,431	6	33,501	(28,416)	5,085
Electric commodity	-	-	1,130	1,130	(1,130)	-
Natural gas commodity	577	94,650	-	95,227	(43,323)	51,904
Total current derivative liabilities	$3,641	$125,886	$1,136	$130,663	$ (72,926)	57,737
Purchased power agreements (b)						23,192
Current derivative instruments valuation						$80,929
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$28,824	$-	$28,824	$ (8,024)	$20,800
Natural gas commodity	-	1,147	-	1,147	(1)	1,146
Total noncurrent derivative liabilities	$-	$29,971	$-	$29,971	$ (8,025)	21,946
Purchased power agreements (b)						277,333
Noncurrent derivative instruments valuation						$299,279

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $99.9 million of equity investments in unconsolidated subsidiaries and $28.3 million of miscellaneous investments.

(b) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting contained in ASC 815 Derivatives and Hedging, 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.

(c) ASC 815 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.

Xcel Energy recognizes transfers between levels as of the beginning of each period. The following table presents the transfers that occurred between levels during the three and nine months ended Sept. 30, 2010.

	From Level 3 to Level 2 (a) (b)	
(Thousands of Dollars)	Three Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2010
Trading commodity derivatives not designated as cash flow hedges:		
Current assets	$ 716	$ 7,271
Noncurrent assets	12,313	26,438
Current liabilities	(776)	(4,115)
Noncurrent liabilities	(9,269)	(16,069)
Total	$ 2,984	$ 13,525

(a) The transfer of amounts from Level 3 to Level 2 is due to the valuation of certain long term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.
(b) There were no transfers of amounts from Level 2 to Level 3.

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The following table presents for each of the hierarchy levels, Xcel Energy's assets and liabilities that are measured at fair value on a recurring basis at Dec. 31, 2009:

	Dec. 31, 2009					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (c)	Total
Current derivative assets						
Other derivative instruments:						
Trading commodity	$-	$16,128	$7,241	$23,369	$ (13,763)	$9,606
Electric commodity	-	-	23,540	23,540	1,425	24,965
Natural gas commodity	-	10,921	-	10,921	165	11,086
Total current derivative assets	$-	$27,049	$30,781	$57,830	$ (12,173)	45,657
Purchased power agreements (b)						52,043
Current derivative instruments valuation						$97,700
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$154	$-	$154	$ -	$154
Other derivative instruments:						
Trading commodity	-	8,554	13,145	21,699	(3,516)	18,183
Natural gas commodity	-	527	-	527	254	781
Total noncurrent derivative assets	$-	$9,235	$13,145	$22,380	$ (3,262)	19,118
Purchased power agreements (b)						270,412
Noncurrent derivative instruments valuation						$289,530
Other recurring fair value assets						
Nuclear decommissioning fund: (a)						
Cash equivalents	$-	$28,134	$-	$28,134	$ -	$28,134
Debt securities:						
Government securities	-	74,126	-	74,126	-	74,126
US corporate bonds	-	312,844	-	312,844	-	312,844
Foreign securities	-	9,445	-	9,445	-	9,445
Municipal bonds	-	149,088	-	149,088	-	149,088
Asset-backed securities	-	-	11,918	11,918	-	11,918
Mortgage-backed securities	-	-	81,189	81,189	-	81,189
Equity securities (common stock)	581,995	-	-	581,995	-	581,995
Total nuclear decommissioning fund	$581,995	$573,637	$93,107	$1,248,739	$ -	$1,248,739

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	Dec. 31, 2009					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (c)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$3,243	$-	$3,243	$ -	$3,243
Other derivative instruments:						
Trading commodity	-	17,803	4,566	22,369	(18,093)	4,276
Electric commodity	-	-	3,276	3,276	1,425	4,701
Natural gas commodity	-	6,749	-	6,749	165	6,914
Other commodity	-	-	360	360	-	360
Total current derivative liabilities	$-	$27,795	$8,202	$35,997	$ (16,503)	19,494
Purchased power agreements (b)						27,060
Current derivative instruments valuation						$46,554
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$5,384	$7,682	$13,066	$ (3,521)	$9,545
Natural gas commodity	-	662	-	662	254	916
Total noncurrent derivative liabilities	$-	$6,046	$7,682	$13,728	$ (3,267)	10,461
Purchased power agreements (b)						297,309
Noncurrent derivative instruments valuation						$307,770

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $104.5 million of equity investments in unconsolidated subsidiaries and $28.6 million of miscellaneous investments.

(b) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting contained in ASC 815 Derivatives and Hedging, 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.

(c) ASC 815 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 methods utilized to measure the fair value of commodity derivatives include the use of forward prices and volatilities to value commodity forwards and options. Levels are assigned to these fair value measurements based on the significance of the use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or the significance of contractual settlements that extend to periods beyond those readily observable on active exchanges or quoted by brokers. Electric commodity derivatives include FTRs, for which fair value is determined using complex predictive models and inputs including forward commodity prices as well as subjective forecasts of retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, fair value measurements for FTRs have been assigned a Level 3.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities presented in the consolidated balance sheets.

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Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including money market funds, are also monitored as additional support for determining fair value. Equity securities are valued using quoted prices in active markets. The fair values for commingled funds and international equity funds 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. Debt securities are primarily priced using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, which also require significant, subjective risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated prepayments. Therefore, fair value measurements for asset-backed and mortgage-backed securities have been assigned a Level 3.

The following tables present the changes in Level 3 recurring fair value measurements for the three and nine months ended Sept. 30, 2010 and 2009:

	Three Months Ended Sept. 30,					
	2010			2009		
		Nuclear Decommissioning Fund			Nuclear Decommissioning Fund	
(Thousands of Dollars)	Commodity Derivatives, Net	Mortgage-Backed Securities	Asset-Backed Securities	Commodity Derivatives, Net	Mortgage-Backed Securities	Asset-Backed Securities
Balance at July 1	$9,806	$65,059	$ 40,067	$49,311	$72,230	$ 14,107
Purchases and settlements, net	721	(1,949)	(5,744)	(1,557)	7,332	(1,542)
Transfers (out of) into Level 3	(2,984)	-	-	1,202	-	-
(Losses) gains recognized in earnings	(10,086)	-	-	1,197	-	-
Gains (losses) recognized as regulatory assets and liabilities	6,691	1,286	171	(5,832)	5,820	286
Balance at Sept. 30	$4,148	$64,396	$ 34,494	$44,321	$85,382	$ 12,851

	Nine Months Ended Sept. 30,					
	2010			2009		
		Nuclear Decommissioning Fund			Nuclear Decommissioning Fund	
(Thousands of Dollars)	Commodity Derivatives, Net	Mortgage-Backed Securities	Asset-Backed Securities	Commodity Derivatives, Net	Mortgage-Backed Securities	Asset-Backed Securities
Balance at Jan. 1	$28,042	$81,189	$ 11,918	$23,221	$98,461	$ 10,962
Purchases and settlements, net	(438)	(21,647)	22,189	(2,779)	(22,702)	366
Transfers (out of) into Level 3	(13,525)	-	-	1,770	-	-
Losses recognized in earnings	(6,711)	-	-	(878)	-	-
(Losses) gains recognized as regulatory assets and liabilities	(3,220)	4,854	387	22,987	9,623	1,523
Balance at Sept. 30	$4,148	$64,396	$ 34,494	$44,321	$$85,382	$ 12,851

Losses on Level 3 commodity derivatives recognized in earnings for the three and nine months ended Sept. 30, 2010, include $2.7 million of net unrealized losses and $6.0 million of net unrealized gains, respectively, relating to commodity derivatives held at Sept. 30, 2010. Gains on Level 3 commodity derivatives recognized in earnings for the three months ended Sept. 30, 2009, included $2.3 million of net unrealized gains relating to commodity derivatives held at Sept. 30, 2009. Losses on Level 3 commodity derivatives recognized in earnings for the nine months ended Sept. 30, 2009, included $6.7 million of net unrealized gains relating to commodity derivatives held at Sept. 30, 2009. Realized and unrealized gains and losses on commodity trading activities are included in electric revenues. Realized and unrealized gains and losses on non-trading derivative instruments are recorded in OCI or deferred as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on the commission approved regulatory recovery mechanisms. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

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11. Financial Instruments

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

(Thousands of Dollars)	Sept. 30, 2010 Carrying Amount	Sept. 30, 2010 Fair Value	Dec. 31, 2009 Carrying Amount	Dec. 31, 2009 Fair Value
Nuclear decommissioning fund	$1,315,118	$1,315,118	$1,248,739	$1,248,739
Other investments	9,036	9,036	9,649	9,649
Long-term debt, including current portion	9,279,202	10,563,272	8,432,442	9,026,257

The fair value of cash and cash equivalents, notes and accounts receivable, notes and accounts payable and short-term debt are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates. The fair value of Xcel Energy's nuclear decommissioning fund is based on published trading data and pricing models, generally using the most observable inputs available for each class of security. The fair values of Xcel Energy's other investments are estimated based on quoted market prices for those or similar investments. The fair value of Xcel Energy's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Sept. 30, 2010 and Dec. 31, 2009. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since that date, and current estimates of fair values may differ significantly.

Guarantees — Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy's exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

The following table presents guarantees issued and outstanding for Xcel Energy:

(Millions of Dollars)	Sept. 30, 2010	Dec. 31, 2009
Guarantees issued and outstanding	$ 69.7	$ 76.4
Known exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	26.7	29.9

Letters of Credit — Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2010 and Dec. 31, 2009, there were $11.0 million and $22.2 million of letters of credit outstanding, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

12. Other Income (Expense), Net

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

(Thousands of Dollars)	Three Months Ended Sept. 30, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
Interest income	$ 4,880	$ 2,709	$ 8,174	$ 8,775
COLI settlement (See Note 5)	25,000	-	25,000	-
Other nonoperating income	-	248	1,105	3,078
Insurance policy expense	(2,362)	(3,534)	(4,110)	(6,877)
Other nonoperating expense	(68)	(400)	(35)	(582)
Other income (expense), net	$ 27,450	$ (977)	$ 30,134	$ 4,394

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13. Segment Information

Xcel Energy has the following reportable segments: regulated electric, regulated natural gas and all other. Commodity trading operations performed by regulated operating companies are not a reportable segment and are included in the regulated electric segment. All other includes the holding company, non-regulated operations of the utility subsidiaries and other non-regulated subsidiaries, including Eloigne.

Xcel Energy had equity investments in unconsolidated subsidiaries of $99.9 million and $104.5 million of as of Sept. 30, 2010 and Dec. 31, 2009, respectively included in the regulated natural gas segment.

Asset and capital expenditure information is not provided for Xcel Energy’s reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common operating and maintenance 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, 2010					
Operating revenues from external customers	$2,440,917	$170,594	$17,276	$ -	$ 2,628,787
Intersegment revenues	268	4,258	-	(4,526)	-
Total revenues	$2,441,185	$174,852	$17,276	$ (4,526)	$ 2,628,787
Income (loss) from continuing operations	$303,301	$(5,167)	$14,354	$ -	$ 312,488
Three Months Ended Sept. 30, 2009					
Operating revenues from external customers	$2,128,955	$169,601	$16,006	$ -	$ 2,314,562
Intersegment revenues	151	584	-	(735)	-
Total revenues	$2,129,106	$170,185	$16,006	$ (735)	$ 2,314,562
Income (loss) from continuing operations	$235,751	$(1,000)	$(12,958)	$ -	$ 221,793

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2010					
Operating revenues from external customers	$6,477,211	$1,210,154	$56,648	$ -	$ 7,744,013
Intersegment revenues	730	8,818	-	(9,548)	-
Total revenues	$6,477,941	$1,218,972	$56,648	$ (9,548)	$ 7,744,013
Income (loss) from continuing operations	$557,482	$68,102	$(10,131)	$ -	$ 615,453
Nine Months Ended Sept. 30, 2009					
Operating revenues from external customers	$5,749,207	$1,224,161	$52,819	$ -	$ 7,026,187
Intersegment revenues	569	2,505	-	(3,074)	-

Total revenues	$5,749,776	$1,226,666	$52,819	$ (3,074)	$ 7,026,187
Income (loss) from continuing operations	$473,392	$71,070	$(29,787)	$ -	$ 514,675

14. Common Stock and Equivalents

Xcel Energy has common stock equivalents consisting of 401(k) equity awards, stock options and equity forward instruments. Restricted stock units and performance shares are considered common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the reporting period.

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Equity Forward Instruments

In August 2010, Xcel Energy entered into equity forward agreements in connection with a public offering of 19 million shares of Xcel Energy common stock. Under the equity forward agreements (Forward Agreements), Xcel Energy agreed to issue to the banking counterparty 21.85 million shares of its common stock, including an over allotment of 2.85 million shares.

The forward price used to determine cash proceeds due Xcel Energy at settlement of the equity forward instruments underlying the Forward Agreements will be calculated based on the August 2010 public offering price of Xcel Energy's common stock, adjusted for underwriting fees, as well as the federal funds rate, less a spread of 0.50 percent, and expected dividends on Xcel Energy's common stock during the period the instruments are outstanding. Xcel Energy may settle the equity forward instruments at any time up to the maturity date of May 15, 2011. Xcel Energy may also unilaterally elect cash or net share settlement for any date up to maturity, for all or a portion of the equity forward instruments.

The equity forward instruments held by the banking counterparty, underlying the Forward Agreements, were accounted for as equity in accordance with ASC 815-40 Derivatives and Hedging - Contracts in Entity's Own Equity, and recorded at fair value at the execution of the Forward Agreements, and will not be subsequently adjusted for changes in fair value until settlement. Since the initial pricing of the equity forward instruments of $20.855 per share was determined based on the August 2010 offering price of Xcel Energy's common stock of $21.50 per share, less underwriting fees of $0.645 per share, no premium on the transaction was due either party to the Forward Agreements at execution, and no fair value was recorded to equity for the instruments. Proceeds or payments due at settlement of all or portions of the equity forward instruments will be recorded with appropriate adjustments to additional paid in capital and common stock, depending on the method of settlement.

Based on the closing Xcel Energy common stock price of $22.97 on Sept. 30, 2010, and the forward price on that date of $20.59, the physical settlement value of the 21.85 million equity forward instruments was approximately $51.9 million. The Forward Agreements require up to a 40 business day notice for cash and net share settlement. Forward prices and volume-weighted average market prices for the period between when notice is provided and settlement are used to calculate cash and net share settlement amounts.

At Sept. 30, 2010, the equity forward instruments could have been settled with physical delivery of 21.85 million shares to the banking counterparty in exchange for cash of $450.0 million. Assuming required notices and actions occurred, the forward instruments could also have been settled at Sept. 30, 2010 with delivery of cash of approximately $38.1 million or approximately 1.650 million shares of common stock to the banking counterparty, to effect cash or net share settlement, respectively, based on an average forward price of $20.81, a volume-weighted average market price of $22.52, and expected dividends of $0.7 million between notice and settlement.

Basic and Diluted Earnings Per Share Calculation

The dilutive impact of common stock equivalents affected earnings per share as follows for the three and nine months ended Sept. 30, 2010 and 2009:

	Three Months Ended Sept. 30, 2010			Three Months Ended Sept. 30, 2009		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$312,306			$220,828		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		

Basic earnings per share:						
Earnings available to common shareholders	311,246	460,471	$0.68	219,768	456,769	$0.48
Effect of dilutive securities:						
401(k) equity awards		581			683	
Equity forward instruments		967			-	
Stock options	-	-		-	1	
Diluted earnings per share:						
Earnings available to common shareholders	$311,246	462,019	$0.67	$219,768	457,453	$0.48

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(Amounts in thousands, except per share data)	Nine Months Ended Sept. 30, 2010 Income	Shares	Per Share Amount	Nine Months Ended Sept. 30, 2009 Income	Shares	Per Share Amount
Net income	$619,200			$512,002		
Less: Dividend requirements on preferred stock	(3,180)			(3,180)		
Basic earnings per share:						
Earnings available to common shareholders	616,020	459,816	$1.34	508,822	456,095	$1.12
Effect of dilutive securities:						
401(k) equity awards	-	583		-	634	
Equity forward instruments	-	323		-	-	
Diluted earnings per share:						
Earnings available to common shareholders	$616,020	460,722	$1.34	$508,822	456,729	$1.11

The computation of diluted earnings per share excludes the following anti-dilutive shares for the three and nine months ended Sept. 30, 2010 and 2009:

(In Thousands)	Three Months Ended Sept. 30, 2010	2009	Nine Months Ended Sept. 30, 2010	2009
Stock options	5,185	7,289	6,102	7,685

15. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended Sept. 30,			
	2010	2009	2010	2009
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$18,286	$16,365	$1,002	$1,166
Interest cost	41,253	42,448	10,695	12,603
Expected return on plan assets	(58,080)	(64,135)	(7,132)	(5,694)
Amortization of transition obligation	-	-	3,611	3,611
Amortization of prior service cost (credit)	5,165	6,155	(1,233)	(681)
Amortization of net loss	12,078	3,114	2,910	4,832
Net periodic benefit cost	18,702	3,947	9,853	15,837
Costs not recognized and additional cost recognized due to the effects of regulation	(6,630)	(723)	972	972
Net benefit cost recognized for financial reporting	$12,072	$3,224	$10,825	$16,809

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2010	2009	2010	2009
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$54,860	$49,095	$3,005	$3,499
Interest cost	123,758	127,343	32,085	37,809
Expected return on plan assets	(174,239)	(192,404)	(21,397)	(17,082)
Amortization of transition obligation	-	-	10,833	10,833
Amortization of prior service cost (credit)	15,493	18,464	(3,699)	(2,044)
Amortization of net loss	36,236	9,342	8,732	14,497
Net periodic benefit cost	56,108	11,840	29,559	47,512
Costs not recognized and additional cost recognized due to the effects of regulation	(20,270)	(2,169)	2,918	2,918
Net benefit cost recognized for financial reporting	$35,838	$9,671	$32,477	$50,430

16. PSCo Agreement to Acquire Assets from Calpine

In April 2010, PSCo reached an agreement with Riverside Energy Center LLC and Calpine Development Holdings, Inc. to purchase the Rocky Mountain Energy Center and Blue Spruce Energy Center natural gas generation assets for $739 million.

The Rocky Mountain Energy Center is a 652 MW combined-cycle natural gas-fired power plant that began commercial operations in 2004. The Blue Spruce Energy Center is a 310 MW simple cycle natural gas-fired power plant that began commercial operations in 2003. Both power plants currently provide energy and capacity to PSCo under power purchase agreements, which were set to expire in 2013 and 2014.

The acquisition is subject to federal and state regulatory approvals including approval of the proposed recovery of costs. In June 2010, the Federal Trade Commission provided notice of the early termination of the waiting period under Hart-Scott-Rodino. In July 2010, the FERC issued an order approving the acquisition.

In September 2010, PSCo reached a partial settlement with the CPUC staff, the Colorado Independent Energy Association and the OCC, which provided for recovery of the revenue requirement (capital and O&M costs) associated with the transaction through an interim rider mechanism less a $3.9 million annual revenue reduction until PSCo implements new retail base rates. Additionally, in its next retail rate case, PSCo shall be allowed recovery of the net book value, based on the $739 million purchase price.

On Oct. 18, 2010, the CPUC approved the acquisition and the cost recovery settlement. The CPUC also required PSCo to file a rate case by April 30, 2012 to move the investment into rate base. The revenue requirements associated with the asset acquisition will continue to be recovered through the purchase capacity cost adjustment until final rates are implemented. Fuel costs will continue to flow through the energy cost adjustment and fuel cost adjustment mechanisms. The acquisition is expected to close in December 2010.

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 unaudited consolidated financial statements and related notes to the consolidated financial statements. Due to the seasonality of Xcel Energy’s electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results.

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Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outlook,” “plan,” “project,” “possible,” “potential,” “should” and similar expressions. results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; environmental laws and regulations; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including “Risk Factors” in Item 1A of Xcel Energy’s Form 10-K for the year ended Dec. 31, 2009, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2010.

Financial Review

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

Results of Operations

The following table summarizes the diluted earnings per share for Xcel Energy:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
Diluted Earnings (Loss) Per Share	2010	2009	2010	2009
PSCo	$ 0.29	$ 0.20	$ 0.69	$ 0.51
NSP-Minnesota	0.24	0.20	0.48	0.48
SPS	0.08	0.08	0.16	0.14
NSP-Wisconsin	0.04	0.03	0.08	0.08
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.02
Regulated utility — continuing operations	0.66	0.52	1.44	1.23
Holding company and other costs	(0.04)	(0.04)	(0.10)	(0.11)
Ongoing diluted earnings per share	0.62	0.48	1.34	1.12
COLI settlement, PSRI and Medicare Part D	0.05	-	(0.01)	(0.01)
Earnings per share from continuing operations	0.67	0.48	1.33	1.11

Earnings per share from discontinued operations	-	-	0.01	-
GAAP diluted earnings per share	$ 0.67	$ 0.48	$ 1.34	$ 1.11

Third quarter 2010 ongoing earnings, which exclude adjustments for certain non-recurring items, were $0.62 per share, compared with $0.48 per share in 2009. Ongoing earnings for the third quarter of 2010 increased primarily due to warmer temperatures, rate increases, the timing of revenue collection due to implementation of seasonal rates and a lower effective tax rate. Temperatures for the third quarter of 2010 were warmer than normal, while temperatures in the third quarter of 2009 were cooler than normal.

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.

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Earnings Adjusted for Certain Non-recurring Items (Ongoing Earnings)

PSCo — Earnings at PSCo increased by $0.09 per share for the third quarter and by $0.18 per share for the nine months ended Sept. 30, 2010. The increases are primarily due to rate increases, the timing of revenue collection as a result of the implementation of seasonal rates in June 2010 and warmer temperatures, which increase electric sales. The increase was partially offset by higher O&M expenses and depreciation expense. Seasonal rates are designed to be revenue neutral on an annual basis. As a result, the quarterly pattern of revenue collection is expected to be different than in the past as seasonal rates are higher in the summer months and lower throughout the remainder of the year. Therefore, it is anticipated that this positive revenue trend will partially reverse in the fourth quarter.

NSP-Minnesota — Earnings at NSP-Minnesota increased by $0.04 per share for the third quarter and were flat for the nine months ended Sept. 30, 2010. The third quarter increase is largely due to the positive impact of warmer temperatures and weather normalized sales growth, partially offset by higher O&M expenses and depreciation expense.

SPS — Earnings at SPS were flat for the third quarter and increased by $0.02 per share for the nine months ended Sept. 30, 2010. The year to date increase is mainly due to electric sales growth, which was partially offset by higher O&M expenses.

NSP-Wisconsin — Earnings at NSP-Wisconsin increased by $0.01 per share for the third quarter and were flat for the nine months ended Sept. 30, 2010. The third quarter increase is due to warmer temperatures, which increased electric sales, as well as new electric rates, which were effective in January 2010, partially offset by higher O&M expenses.

Non-recurring Items

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

Impact of the Patient Protection and Affordable Care Act — Medicare Part D
During the first quarter of 2010, Xcel Energy recorded non-recurring tax expense of approximately $17 million, or $0.04 per share, of tax benefits previously recognized in income related to Medicare Part D subsidies due to the Patient Protection and Affordable Care Act enacted in March 2010. Under GAAP, Xcel Energy was required to reverse these previously recorded tax benefits in the period of enactment of the new legislation.

PSRI
In addition, during the first quarter of 2010, Xcel Energy recorded a non-recurring tax and interest charge of approximately $10 million, or $0.02 per share, due to an agreement in principle reached with the IRS following the completion of a financial reconciliation of Xcel Energy's statement of account dating back to tax year 1993, related to the COLI program. During the third quarter of 2010, Xcel Energy and the IRS came to final agreement on the applicable interest netting computations related to these tax years. Accordingly, PSRI recorded a reduction to expense of $0.6 million, net of tax, during the third quarter of 2010.

See Note 5 to the consolidated financial statements for further discussion of the COLI settlement, PSRI, and Medicare Part D.

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The following table summarizes the components of change in ongoing diluted earnings per share:

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30,	Nine Months Ended Sept. 30,
2009 GAAP diluted earnings per share	$ 0.48	$ 1.11
PSRI	-	0.01
2009 ongoing diluted earnings per share	0.48	1.12
Components of change — 2010 vs 2009		
Higher electric margins	0.24	0.46
Higher natural gas margins	0.01	0.03
Higher operating and maintenance expenses	(0.06)	(0.13)
Higher depreciation and amortization	(0.03)	(0.04)
Higher conservation and DSM expenses (generally offset in revenues)	(0.02)	(0.05)
Lower AFUDC — equity	(0.01)	(0.03)
Higher taxes (other than income taxes)	-	(0.02)
Other, net	0.01	-
2010 ongoing diluted earnings per share	0.62	1.34
COLI settlement, PSRI and Medicare Part D	0.05	(0.01)
2010 earnings per share from continuing operations	0.67	1.33
Earnings per share from discontinued operations	-	0.01
2010 GAAP diluted earnings per share	$ 0.67	$ 1.34

The following table summarizes the earnings contributions of Xcel Energy's business segments on the basis of GAAP. See Note 4 to the consolidated financial statements for further discussion of discontinued operations:

Contributions to Income (Millions of Dollars)	Three Months Ended Sept. 30, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
GAAP income (loss) by segment				
Regulated electric income	$ 303.3	$ 235.8	$ 557.5	$ 473.4
Regulated natural gas income	(5.2)	(1.0)	68.1	71.1
Other income (a)	31.0	4.2	30.6	17.9
Segment income — continuing operations	329.1	239.0	656.2	562.4
Holding company and other costs (a)	(16.6)	(17.2)	(40.7)	(47.7)
Total income — continuing operations	312.5	221.8	615.5	514.7
Income (loss) from discontinued operations	(0.2)	(1.0)	3.7	(2.7)
Total GAAP net income	$ 312.3	$ 220.8	$ 619.2	$ 512.0

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Contributions to Earnings Per Share	Three Months Ended Sept. 30, 2010	Three Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2009
GAAP earnings (loss) by segment				
Regulated electric	$ 0.66	$ 0.50	$ 1.21	$ 1.04
Regulated natural gas	(0.01)	-	0.15	0.15
Other (a)	0.06	0.02	0.07	0.03
Segment earnings per share — continuing operations	0.71	0.52	1.43	1.22
Holding company and other costs(a)	(0.04)	(0.04)	(0.10)	(0.11)
Total earnings per share — continuing operations	0.67	0.48	1.33	1.11
Discontinued operations	-	-	0.01	-
Total GAAP earnings per share — diluted	$ 0.67	$ 0.48	$ 1.34	$ 1.11

(a) Not a reportable segment. Included in all other segment results in Note 13 to the consolidated financial statements.

Statement of Income Analysis

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

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

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

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process. The percentage increase (decrease) in normal and actual HDD, CDD and THI for the three and nine months ended Sept. 30, 2010 and 2009 are provided in the following table:

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009
HDD	(30.1)%	(24.7)%	(7.1)%	(3.7)%	(2.7)%	(1.1)%
CDD	8.8	(11.8)	23.3	11.4	(10.0)	23.8

THI	35.7	(41.4)	131.4	28.3	(34.0)	94.4

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Weather — The following table summarizes the estimated impact on earnings per share of temperature variations compared with sales under normal weather conditions.

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009
Retail electric	$ 0.04	$ (0.05)	$ 0.09	$ 0.05	$ (0.05)	$ 0.10
Firm natural gas	0.00	0.00	0.00	(0.01)	(0.01)	0.00
Total	$ 0.04	$ (0.05)	$ 0.09	$ 0.04	$ (0.06)	$ 0.10

Sales Growth (Decline) — The following table summarizes Xcel Energy's regulated sales growth (decline) for actual and weather-normalized sales for 2010 as compared with the same periods in 2009.

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
	Actual	Normalized	Actual	Normalized
Electric residential	13.1 %	0.1 %	7.3 %	1.4 %
Electric commercial and industrial	5.0	1.5	2.9	1.4
Total retail electric sales	7.3	1.2	4.1	1.4
Firm natural gas sales	(5.1)	(1.9)	2.2	0.4

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 tables detail the electric revenues and margin:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009	2010	2009
Electric revenues	$ 2,441	$ 2,129	$ 6,477	$ 5,749
Electric fuel and purchased power	(1,111)	(982)	(3,085)	(2,704)
Electric margin	$ 1,330	$ 1,147	$ 3,392	$ 3,045

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, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Retail rate increases, including seasonal rates (Colorado, Wisconsin, South Dakota and New Mexico)	$ 88	$ 210
Fuel and purchased power cost recovery	87	331
Estimated impact of weather	58	69
NSP-Minnesota 2009 rate case adjustment for final rates (largely offset in depreciation expense)	25	-

Non-fuel riders	13	9
Conservation and DSM revenue and incentive (partially offset by expenses)	11	39
Retail sales increase (excluding weather impact)	4	18
Sales mix and demand revenue	(4)	13
Firm wholesale	(2)	(11)
Other, net	32	50
Total increase in electric revenues	$ 312	$ 728

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Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Retail rate increases, including seasonal rates (Colorado, Wisconsin, South Dakota and New Mexico)	$ 88	$ 210
Estimated impact of weather	58	69
NSP-Minnesota 2009 rate case adjustment for final rates (largely offset in depreciation expense)	25	-
Non-fuel riders	13	9
Conservation and DSM revenue and incentive (partially offset by expenses)	11	39
Retail sales increase (excluding weather impact)	4	18
Sales mix and demand revenue	(4)	13
Other, net (including trading and deferred fuel adjustments)	(12)	(11)
Total increase in electric margin	$ 183	$ 347

In December 2009, the CPUC approved a rate increase of approximately $128.3 million; however, due to the delay in Comanche Unit 3 coming online, the CPUC approved PSCo's proposal to phase in the approved electric rate increase to reflect the actual cost of service. Under the plan, the following increases have or will be implemented:

- A rate increase of $67 million was implemented on Jan. 1, 2010 because of the delay of the in-service date of Comanche Unit 3;
- Base rates were increased to recover $123 million annually, on May 14, 2010 when Comanche Unit 3 went into service, including an additional $2 million of recovery for long-term debt interest in the working capital calculation granted under reconsideration; and
- Base rates will increase to recover approximately $130 million annually on Jan. 1, 2011 to reflect 2011 property taxes.

A second phase of the rate case addressed changes to rate design. The new rates, approved by the CPUC, went into effect on June 1, 2010. In this phase of the proceeding, the CPUC approved tiered summer rates for residential customers and seasonally differentiated rates for other customer classes, which will impact the timing of revenue collection, as compared to the previous rate design, depending on customer response. Third quarter and year to date electric revenue and margin for 2010 were positively impacted by approximately $45 million and $53 million, respectively, related to the implementation of such rate design and seasonal rates. Seasonal rates are designed to be revenue neutral on an annual basis. However, the quarterly pattern of revenue collection is expected to be different than in the past as seasonal rates are higher in the summer months and lower throughout the remainder of the year. It is anticipated that this positive electric revenue and margin trend will partially reverse in the fourth quarter.

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 tables detail natural gas revenues and margin:

	Three Months Ended Sept. 30,	Nine Months Ended Sept. 30,

(Millions of Dollars)	2010	2009	2010	2009
Natural gas revenues	$ 171	$ 170	$ 1,210	$ 1,224
Cost of natural gas sold and transported	(67)	(72)	(775)	(810)
Natural gas margin	$ 104	$ 98	$ 435	$ 414

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Purchased natural gas adjustment clause recovery	$ (4)	$ (30)
Conservation and DSM revenue and incentive (partially offset by expenses)	4	9
Rate increase (Minnesota interim)	1	4
Other, net	-	3
Total increase (decrease) in natural gas revenues	$ 1	$ (14)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Conservation and DSM revenue and incentive (partially offset by expenses)	$ 4	$ 9
Rate increase (Minnesota interim)	1	4
Other, net	1	8
Total increase in natural gas margin	$ 6	$ 21

Non-Fuel Operating Expense and Other Items

O&M Expenses — O&M expenses increased by approximately $43.2 million, or 9.3 percent, for the third quarter and by $96.5 million, or 6.8 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The following table summarizes the changes in other O&M expenses:

(Millions of Dollars)	Three Months Ended Sept. 30, 2010 vs. 2009	Nine Months Ended Sept. 30, 2010 vs. 2009
Higher employee benefit costs	$ 14	$ 18
Higher plant generation costs	7	24
Higher labor costs	7	18
Higher nuclear plant operation costs	5	10
Higher insurance costs	1	8
Nuclear outage costs, net of deferral	-	10
Other, net	9	9
Total increase in other operating and maintenance expenses	$ 43	97

- Higher employee benefit costs are primarily related to performance based incentive compensation as well as pension costs.
-

Higher plant generation costs are primarily attributable to higher levels of scheduled maintenance and overhaul work as well as incremental operating costs associated with new generation facilities placed in service in the current year.

- Higher labor costs are primarily due to an increase in compliance requirements, higher overtime for storm restoration work, and a shift in labor resources from capital to O&M projects.
- Higher nuclear outage costs are due to the timing and cost of nuclear refueling outages.
- Higher insurance costs are due to general premium increases.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses increased by approximately $13.7 million, or 29.1 percent, for the third quarter and by $40.7 million, or 30.4 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The higher expense is attributable to the expansion of programs and regulatory commitments. Xcel Energy's operating companies have established DSM or CIP in many of their retail jurisdictions. Overall, the programs are designed to encourage the operating companies and their retail customers to conserve energy or change energy usage patterns in order to reduce peak demand on the gas and/or electric system. This, in turn, reduces the need for additional plant capacity, reduces emissions, serves to achieve other environmental goals as well as reduces energy costs to participating customers. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

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Depreciation and Amortization — Depreciation and amortization expenses increased by approximately $23.4 million, or 11.8 percent, for the third quarter and by $30.0 million, or 4.9 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. In September 2009, as a result of the MPUC decisions in the Minnesota electric rate case, NSP-Minnesota began recognizing a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation, effective Jan. 1, 2009. In addition, in June 2009, the MPUC extended the recovery period of decommissioning expense by 10 years for the Prairie Island and the Monticello nuclear plants. Excluding the one time decrease recognized in 2009, the change in depreciation expense from 2009 to 2010 is primarily due to Comanche Unit 3 going into service and normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased by approximately $2.9 million, or 3.6 percent, for the third quarter and by $15.2 million, or 6.6 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily due to an increase in property taxes in Colorado and Minnesota.

Other Income (Expense), Net — Other income (expense), net increased by approximately $28.4 million for the third quarter and by $25.7 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily due to the COLI settlement in July 2010.

Equity Earnings of Unconsolidated Subsidiaries — Equity earnings of unconsolidated subsidiaries increased by approximately $3.3 million for the third quarter and by $11.7 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is primarily related to increased earnings from the equity investment in WYCO Development LLC, which includes a natural gas pipeline and a storage facility that began operating in 2008 and mid 2009, respectively.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC decreased by approximately $8.4 million for the third quarter and by $24.9 million for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The decrease was partially due to Comanche Unit 3 going into service and lower AFUDC rates.

Interest Charges — Interest charges increased by approximately $5.5 million, or 3.9 percent, for the third quarter and by $9.7 million, or 2.3 percent for the nine months ended Sept. 30, 2010, compared with the same periods in 2009. The increase is due to higher long-term debt levels to fund investment in our utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations increased by $30.6 million for the third quarter of 2010, compared with the same period in 2009. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 34.7 percent for the third quarter of 2010, compared with 37.9 percent for the same period in 2009. The higher effective tax rate for the third quarter of 2009 was primarily due to the recognition of additional state unitary tax expense and the establishment of a valuation allowance against certain state tax credit carryovers that were expected to expire.

Income tax expense for continuing operations increased by $84.4 million for the nine months ended Sept. 30, 2010, compared with the same period in 2009. The increase in income tax expense was primarily due to an increase in pretax income, one time adjustments for a write-off of tax benefit previously recorded for Medicare Part D subsidies, and an adjustment related to the COLI Tax Court proceedings, partially offset by a reversal of a valuation allowance for certain state tax credit carryovers. The effective tax rate for continuing operations was 37.2 percent for the nine months ended Sept. 30, 2010, compared with 35.3 percent for the same period in 2009. The higher effective tax rate for the first nine months of 2010 was primarily due to a higher forecasted annual effective tax rate and the adjustments referenced above. Without these one time adjustments, the effective tax rate for continuing operations for the first nine months of 2010 would have been 35.3 percent. Xcel Energy expects the effective tax rate for 2010 ongoing earnings to be approximately 35 percent to 37 percent.

The higher forecasted annual effective tax rate for 2010 continuing operations as compared to 2009, was primarily due to reduced plant-related deductions and the elimination of tax benefits for Medicare Part D subsidies and research credits in 2010, partially offset by the nontaxibility of the Provident settlement in 2010.

Factors Affecting Results of Continuing Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs in Item 7 — Managements Discussion and Analysis of Financial Condition and Results of Operations in Xcel Energy’s Annual Report on Form 10-K filed for the year ended Dec. 31, 2009.

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Public Utility Regulation

NSP-Minnesota

2010 Minnesota Resource Decisions and Plan — In May 2010, NSP-Minnesota signed new power purchase and exchange agreements with Manitoba Hydro that will extend purchases through 2025. The existing agreements provide for the purchase of 850 MW, which start to expire April 30, 2015. NSP-Minnesota filed for approval with the MPUC in June 2010.

NSP-Minnesota filed its 2011-2025 resource plan in August 2010. In addition to the extension of contracts with Manitoba Hydro and previously approved life extensions and capacity increases at NSP-Minnesota's nuclear generating plants, the near term actions in the plan include continued expansion of DSM programs to 1.5 percent of sales annually, the acquisition of up to 250 MW of additional wind power to be in service by 2012 if priced competitively, and the replacement of the remaining 270 MW of coal-fired generation at the Black Dog generating plant with a 680 MW natural gas, combined-cycle unit by 2016.

NSP-Minnesota Transmission Certificate of Need (CON) — In April 2009, the MPUC granted a CON to construct three 345 kilovolt KV electric transmission lines as part of the CapX 2020 project. The project to build the three lines includes construction of approximately 600 miles of new facilities at a cost of approximately $1.7 billion. The allocation of the project cost to NSP-Minnesota and NSP-Wisconsin is estimated to be approximately $900 million. These cost estimates will be revised after the regulatory process is completed. The MPUC also included a condition assuring a portion of the capacity of the Brookings, S.D. to Hampton, Minn. line is used for renewable energy. In September 2009, two intervenors appealed the MPUC's CON decisions in the Minnesota Court of Appeals. On June 8, 2010, the court issued its decision affirming the MPUC's order granting the CONs for the three 345 KV lines. In May 2010, NSP-Minnesota and other CapX 2020 utilities notified the MPUC that the in-service date for the Brookings, S.D. to Hampton, Minn. project is expected to be delayed to the second quarter of 2015, more than one year after the date provided in the MPUC CON decision. The MPUC deliberated on the notice of change and decided to not act on that notice. Instead, the MPUC ordered NSP-Minnesota to provide a report in January 2011 to update the status of the project.

As part of the regulatory process for the CapX 2020 345 KV projects, NSP-Minnesota and Great River Energy have filed four route permit applications with the MPUC. Permit applications for the remaining parts of the three lines are expected to be filed in adjoining states in 2010. Two filed route permit applications have completed the evidentiary hearing processes, and the MPUC issued route permits for the Monticello, Minn. to St. Cloud, Minn. project and five of the six segments of the Brookings, S.D. to Hampton, Minn. project. One segment of the Brookings, S.D. to Hampton, Minn. line was referred back to the ALJ to develop more information concerning the appropriate location to cross the Minnesota River. The other two route applications are expected to be sent to an evidentiary hearing later in 2010 or early 2011.

In July 2009, the MPUC approved the CON application for a 230 KV CapX 2020 transmission line between Bemidji, Minn. to Grand Rapids, Minn. Route permit hearings were concluded in May 2010, and an MPUC decision is anticipated in the fourth quarter of 2010. The Bemidji, Minn. to Grand Rapids, Minn. line is expected to entail construction of approximately 68 miles of new facilities at a cost of $100 million, with construction expected to be completed in 2012. The estimated project cost to NSP-Minnesota is approximately $26 million.

Nuclear Plant Power Uprates and Life Extension

Prairie Island Life Extension — In April 2008, NSP-Minnesota filed an application with the Nuclear Regulatory Commission's (NRC) to renew the operating license of its two nuclear reactors at Prairie Island for an additional 20 years, until 2033 and 2034, respectively. The Prairie Island Indian Community (PIIC) filed contentions in the NRC's license renewal proceeding in August 2008, which was referred to the Atomic Safety and Licensing Board (ASLB) for review. The ASLB granted the PIIC hearing request and has admitted seven of the 11 contentions filed. To date, all seven contentions that were originally admitted have been resolved and removed from the ASLB docket.

Subsequent to the NRC issuance of the final Safety Evaluation Report and the draft supplemental environmental impact statement, the PIIC filed four additional contentions. The ASLB has admitted one of the contentions and has issued a decision denying the other three. On Sept. 30, 2010, the NRC Commissioners reversed the ASLB's decision to admit the one contention. The ASLB was directed to terminate its hearing process. As a result, the NRC staff is proceeding with the remaining items necessary to process Prairie Island's license renewal application and NSP-Minnesota anticipates receiving a final decision on the Prairie Island license renewal sometime in the first quarter of 2011.

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Monticello Nuclear Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello facility. The filing was placed on hold by the NRC staff to address concerns raised by the Advisory Committee for Reactor Safety (ACRS) related to containment pressure associated with pump performance. The industry submitted a white paper and the NRC staff recommended that the matter be addressed through specific filings to demonstrate any potential risk and mitigation measures. In a letter to the NRC staff, the ACRS indicated that modifications to the plant should be evaluated and made where practical. NSP-Minnesota is working with the NRC to supplement its filing as necessary to address the issues and expects to complete the license proceeding in 2011.

Prairie Island Nuclear Extended Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 164 MW for NSP-Minnesota's Prairie Island Units 1 and 2. The MPUC approved the extended power uprate in December 2009. NSP-Minnesota cannot file for NRC approval of the extended power uprate until after the NRC renews the plants' current operating licenses, which is expected in late 2010 or early 2011. The extended power uprates are scheduled to be implemented during the 2014 and 2015 refueling outages.

NSP-Wisconsin

Bay Front Biomass Gasification — In December 2009, the PSCW granted NSP-Wisconsin a certificate of authority to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wis. The initial estimate required for the additional biomass receiving and handling facilities at the plant, an external gasifier, minor modifications to the plant's remaining coal-fired boiler and an enhanced air quality control system was approximately $58 million.

NSP-Minnesota also made filings in North Dakota and Minnesota requesting future rate recovery of the portion of the project costs that will be billed to NSP-Minnesota through the Interchange Agreement.

In the second quarter of 2010, NSP-Wisconsin completed more detailed analyses of the project. As a result of these analyses, the estimated project cost increased to nearly $79.5 million, well above the 10 percent cost tolerance band allowed by the PSCW in the certificate of authority final order. NSP-Wisconsin notified the PSCW of the increase in estimated costs and received a three to six month time period to review other options that may be viable for the third boiler at Bay Front. NSP-Wisconsin expects to complete its review and report its findings to the PSCW by the end of 2010. NSP-Minnesota has withdrawn the rate recovery filings previously submitted to the MPUC and the NDPSC, but may submit revised filings once the regulatory process in Wisconsin is completed.

Wisconsin Fuel Cost Recovery Legislation — In May 2010, Wisconsin adopted a law to modify the existing statutes and rules governing electric fuel cost recovery in utility rates. The prohibition on an automatic adjustment clause remains, but the provision requiring an emergency or extraordinary increase in the cost of fuel before the PSCW can approve a fuel-related rate increase was repealed. As required by the legislation, the PSCW promulgated a rule to implement the change in law and forwarded its proposed rule to the Wisconsin legislature in August 2010. Approval by the legislature is pending.

Under the proposed rule, an electric utility will submit a forward-looking annual fuel cost plan for approval by the PSCW. Once a utility has an approved fuel cost plan, it can then defer any under-collection or over-collection of fuel costs for future rate recovery or refund, providing that the under/over-collection exceeds a 2.0 percent symmetrical annual tolerance band. Approval of a fuel cost plan and any rate adjustment for recovery or refund of deferred costs would be determined by the PSCW after opportunity for a hearing. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. The proposed rule is scheduled to go into effect for calendar year 2011.

PSCo

Resource Plan — In October 2009, the CPUC approved the acquisitions of the resources identified in the bid evaluation report filed with the CPUC in August 2009. With minor modification, the CPUC adopted PSCo's preferred plan, which includes an incremental 900 MW of additional intermittent renewable energy resources (wind and photovoltaic (PV) solar) and approximately 280 MW of "new technology" renewable energy sources. The CPUC approved the selection of about 900 MW of traditional gas-fired resources. The OCC has appealed the CPUC's approval of the resource plan to Denver District Court, arguing that the CPUC erred in approving a portfolio where PSCo obtained an ownership interest in gas-fired generation and that this portfolio will not result in just and reasonable rates.

In May 2010, PSCo filed for approval to purchase approximately 900 MW of gas-fired generation from subsidiaries of Calpine Corporation consistent with the CPUC approved portfolio. PSCo has the ability to terminate the transaction if conditions on regulatory approval are unacceptable. The purchase is subject to federal and state regulatory approvals including approval of the proposed recovery of costs. In June 2010, the Federal Trade Commission provided notice of the early termination of the waiting period for premerger review. In July 2010, the FERC issued an order approving the acquisition.

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In September 2010, PSCo reached partial settlement with CPUC staff, the Colorado Independent Energy Association and the OCC, which provided for recovery of the revenue requirement (capital and O&M costs) associated with the transaction through an interim rider mechanism less a $3.9 million annual revenue reduction until PSCo implements new retail base rates. Additionally, in its next retail rate case, PSCo shall be allowed recovery of the net book value, based on the $739 million purchase price.

On Oct. 18, 2010, the CPUC approved the acquisition and the cost recovery settlement. The CPUC also required PSCo to file a rate case by April 30, 2012 to move the investment into rate base. The revenue requirements associated with the asset acquisition will continue to be recovered through the purchase capacity cost adjustment until final rates are implemented. Fuel costs will continue to flow through the energy cost adjustment and fuel cost adjustment mechanisms. The acquisition is expected to close in December 2010.

In June 2010, PSCo filed an amendment to the approved resource plan to reduce the amount of solar resources (combination of PV solar and new technology renewable energy resources) acquired to an amount that could be accommodated using existing transmission facilities. This change was necessitated by delays in the certificate of public convenience and necessity process to develop a significant new transmission project that would allow access to the Colorado’s best solar resource. The request to reduce solar acquisitions up to 185 MW will ensure that PSCo will not be subject to significant curtailment payments due to use of non-firm transmission. The matter has been referred to an ALJ.

San Luis Valley-Calumet-Comanche Unit 3 Transmission Project — PSCo and Tri-State Generation and Transmission Association filed a joint application with the CPUC for a certificate of public convenience and necessity (CPCN) in May 2009. The project consists of four components of both 230 KV and 345 KV line and substation construction. The line is intended to assist in bringing solar power in the San Luis Valley to load. The line was originally expected to be placed in-service in 2013; however, that appears unlikely now due to delays in the siting and permitting of the line. Several landowners are opposing this transmission line, including two large ranches. A recommended decision from the ALJ is pending.

RES — In March 2010, Colorado enacted a law that increases the RES to 30 percent of energy sales to be supplied by renewable energy for PSCo and removes the solar standard and replaces it with a distributed generation standard. Within the distributed generation standard, at least one-half of the distributed generation must be retail distributed generation, i.e., generation that is on customer premises behind the customer meter. The law requires that PSCo generate or cause to be generated electricity from renewable resources equaling:

- At least 12 percent of its retail sales for the years 2011 through 2014;
- At least 20 percent of its retail sales for the years 2015 through 2019; and
- At least 30 percent of its retail sales for the years 2020 and thereafter.

In addition, distributed generation must equal:

- At least 1 percent of retail sales in the years 2011 and 2012 and 1.25 percent of retail sales in the years 2013 and 2014;
- At least 1.75 percent of retail sales in the years 2015 and 2016 and 2 percent of retail sales in the years 2017, 2018 and 2019; and
- At least 3 percent of retail sales in the years 2020 and thereafter.

The CPUC has discretion to review the reasonableness of the increase in the distributed generation percentage in 2014. PSCo believes that its forecasted plan acquisitions of renewable resources only need minor modification to comply with the new standard.

CACJA — The CACJA was signed into law in April 2010. The CACJA required PSCo to file a comprehensive plan with the CPUC by Aug. 15, 2010 to reduce annual emissions of NOx by at least 70 to 80 percent from 2008 levels from the coal-fired generation identified in the plan. The plan must consider emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by Jan. 1, 2018. The legislation further encourages PSCo to submit long-term gas contracts to the CPUC for approval. If approved, PSCo would be entitled to recover the costs it incurs under these long-term gas contracts, notwithstanding any change in the market price of natural gas during the term of the contract.

Pursuant to the CACJA, PSCo is authorized to recover the costs that it prudently incurs in executing an approved emission reduction plan and is allowed a return on CWIP on plan investments. In addition, if early action is taken to retire or convert units to natural gas, and PSCo shows that the costs of the plan would contribute to an earnings deficiency, additional relief, including a more comprehensive rider to recover other plant costs such as depreciation and O&M expenses, or a multi-year rate plan are allowed. The CACJA permits the CPUC to consider interim rate increases after Jan. 1, 2012 while the rate filing is pending.

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In August 2010, PSCo filed its preferred plan with the CPUC. PSCo's recommended plan has three key components:

- Retires 900 MW of coal generation at its Valmont (186 MW) and Cherokee (717 MW) power plants by the end of 2017 and the end of 2022, respectively;
- Repowers its Cherokee generating facility with efficient, natural gas generation of 883 MW (589 MW in 2015 and 314 MW in 2022). PSCo also will switch to natural gas generation at the 111 MW Arapahoe Unit 4 generating facility in 2013; and
- Retrofits about 950 MW of coal-fired generation at the Pawnee (505 MW) and Hayden (446 MW) generating facilities with modern emission control technology.

The plan would reduce emissions of NOx from the targeted plants by 77 percent at the end 2017, and by 89 percent at the end of 2022. In addition, when compared to 2008 levels, the plan would reduce SO2 emissions by 84 percent and mercury emissions by 85 percent for the power plants targeted under the plan by 2023. The plan also allows PSCo to meet Colorado's statewide carbon dioxide reduction goal of 20 percent before the 2020 target.

The total cost of the plan, if approved by the CPUC, would result in new construction of approximately $1.4 billion over the next 12 years. The rate impact of the proposed plan is expected to increase future bills on average by 1.5 percent annually over the next ten years. The recommended plan costs less than retrofitting all of these units with emission control equipment. The estimated cost of the plan for the years 2011 through 2017 is shown in the table below:

(Millions of Dollars)	2011	2012	2013	2014	2015	2016	2017	Total
Combined cycle	$16.0	$81.0	$203.1	$105.4	$103.1	$25.9	$-	$534.5
Pollution control unit	69.6	82.8	66.3	93.4	26.1	8.6	-	346.8
Transmission	1.2	3.1	3.1	4.5	11.4	-	-	23.3
Gas pipeline	5.9	6.1	57.2	40.7	-	-	-	109.9
Total	$92.7	$173.0	$329.7	$244.0	$140.6	$34.5	$-	$1,014.5

PSCo also proposed to implement a new emission reduction adjustment rate to go into effect around January 2011. This adjustment clause seeks to recover a return on the CWIP for electric investments made pursuant to the plan and also includes the recovery of other plant related costs, such as higher depreciation expense, incurred under the emissions reduction plan. The 2011 expected increase would be approximately $14.1 million.

In September 2010, 51 witnesses filed answer testimony representing over 20 parties in the case. Coal interests generally opposed PSCo's plan and advocated for scenarios in which emissions control retrofits were installed. Gas interests and environmental groups advocated for accelerating the time line of PSCo's proposed plan and advocated for the inclusion of other generation alternatives and energy efficiency. The City and County of Denver, Colo. and the County of Boulder, Colo. supported the plan. Several parties sought changes to the regulatory recovery provisions proposed by PSCo. Hearings began on Oct. 21, 2010, and the CPUC is scheduled to issue a decision by Dec. 15, 2010.

In October 2010, the CPUC ruled that based on the Colorado Department of Public Health and Environment's (CDPHE) interpretation of certain statutory provisions related to reasonably foreseeable air quality regulations, that PSCo's plan to take actions beyond 2017 failed to meet the standards of the CACJA. As a result, PSCo filed supplemental testimony on Oct. 25, 2010 recommending that if the CPUC or the CDPHE can't find the original plan acceptable, that the preferred plan is to install selective catalytic reduction on its Cherokee Unit 4 by 2017.

SmartGridCity™ CPCN — As part of the recent PSCo electric rate case, the CPUC included recovery of the revenue requirements associated with the capital and O&M costs incurred by PSCo to develop and operate SmartGridCity™, subject to refund, and ordered PSCo to file for a CPCN for that project. PSCo is currently recovering the revenue requirements on $42 million of capital costs and $4 million in annual O&M expenses.

In March 2010, PSCo filed the required CPCN. Intervenors filed testimony in July 2010. Two parties, Leslie Glustrom and ArapaHope Community Team (ACT) oppose issuance of the CPCN. The OCC and Glustrom recommended partial recovery of capital costs while ACT recommended no recovery. ACT withdrew from the case before hearing. The OCC recommended recovery of revenue requirements of $27.9 million of capital costs. PSCo reached a settlement with the CPUC staff and the Governor’s Energy Office for approval of the CPCN and cost recovery. PSCo is awaiting a recommended decision from the ALJ.

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SPS

Jones Certificate of Convenience and Necessity (CCN) — SPS applied for a CCN to build a gas-fired combustion turbine generating unit at SPS' existing Jones Station in Lubbock, Texas with the PUCT, which approved the CCN in August 2010. A similar CCN approval application was made with the NMPRC. The parties reached a settlement recommending approval that was filed with the NMPRC on Oct. 7, 2010. A final order is expected in December 2010.

New Mexico Energy Efficiency Disincentive Rulemaking — During the 2008 New Mexico legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. In 2010, the NMPRC adopted an amended rule incorporating the legislative changes. The rule has an interim mechanism that provides for recovery of disincentives and recently required utilities to file permanent rate design or other means of removing disincentives by July 1, 2010.

In June 2010, SPS filed its application for approval of its interim incentive. That same month, an appeal of the rule was filed by the Attorney General and the New Mexico Industrial Energy Consumers with the New Mexico Supreme Court. SPS and the intervenors have reached a settlement agreement for the 2010 and 2011 disincentives and incentives of $3.3 million. The settlement agreement is independent of the NMPRC's ruling. A final order is expected is December 2010. In July 2010, SPS filed its application regarding permanent solutions to removing disincentives and requested direct lost margin recovery. A hearing in this case is scheduled for March 2011.

Solar Contract Approval — In December 2009, SPS entered into five solar energy purchased power agreements (PPAs) with five separate entities associated with SunEdision, LLC (SunE), for the procurement of solar energy and associated RECs to meet its solar diversity requirements. The SunE PPAs involve five facilities, each consisting of 10 MW of capacity for a term of 20 years.

In January 2010, SPS filed a request with the NMPRC to approve SPS' SunE PPAs and authorize SPS to recover the costs of the PPAs from its New Mexico customers. In September 2010, the NMPRC approved the SunE PPAs and SPS' proposed cost recovery.

New Mexico GHG Regulations — SPS may face the future risk of regulation of CO2 emissions from proposed rules in New Mexico. The NMED and New Energy Economy, a non-governmental environmental advocacy organization, have each proposed rules before New Mexico's Environmental Improvement Board (EIB) to limit and reduce GHGs, including CO2 emissions from power plants. The rulemaking process for both proposals is ongoing with a final decision by the EIB likely by the end of 2010. If either proposed rule is adopted in New Mexico, SPS may face additional costs for compliance, possibly including the purchase of carbon offsets or the cost of CO2 emission reductions in the New Mexico portion of the SPS system. Compliance costs for these reductions or offsets may increase electricity rates to New Mexico customers. While regulated utilities generally recover costs resulting from regulatory requirements, SPS may not recover all costs related to complying with the regulatory requirements imposed on us under the proposed rules. The effect on the financial condition of SPS is uncertain, due to the lack of certainty in the final rules, and also due to the relatively small proportion of SPS total greenhouse gases that are emitted in New Mexico. If the EIB adopts one or both of the proposed rules, the anticipated compliance date is 2012.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy's utility subsidiaries, including enforcement of North American Electric Reliability Corporation (NERC) mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy's utility 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 Annual Report on Form 10-K for the year ended Dec. 31, 2009. In addition to the matters discussed below, see Note 6 to the consolidated financial statements for a discussion of other regulatory matters.

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Midwest Independent Transmission System Operator, Inc. (MISO) Cost Allocation Tariff — In October 2009, the FERC approved a proposal by MISO and its transmission owners, including NSP-Minnesota and NSP-Wisconsin, to change the cost allocation procedures in the MISO tariff associated with interconnection of new generation. The approved tariff required the interconnecting generator to fund 90 or 100 percent of the costs of network upgrades required for interconnection (depending on voltage) on an interim basis until MISO and its stakeholders develop a replacement tariff to be filed with FERC in July 2010. On July 15, 2010, MISO and certain transmission owners, including NSP-Minnesota and NSP-Wisconsin, filed the required replacement tariff. The cost allocation provisions of the tariff provide for (1) regional allocation and recovery of costs associated with transmission expansion projects identified through the MISO transmission planning process as Multi-Value Projects (MVPs), which are projects that meet certain key planning objectives and (2) the allocation to generators of most costs for other network upgrades required to interconnect the generator to the MVPs or the existing transmission system. MISO proposed the tariff changes be effective July 16, 2010. Comments on the July 2010 MISO tariff filing were filed on Sept. 10, 2010, and a significant number of comments, both in support and in opposition of the tariff changes, were submitted. The filing is pending FERC action.

MISO vs. PJM Interconnection, L.L.C. (PJM) Complaint Proceedings — In March 2010, MISO filed two complaints against PJM at the FERC alleging that PJM violated generation redispatch requirements under the Joint Operating Agreement between the two regional transmission organizations (RTOs), and alleging that incorrect modeling of certain generators by PJM resulted in underpayments by PJM of up to $135 million to generators in MISO (including the NSP System, whereby NSP-Minnesota and NSP-Wisconsin share all generation and transmission costs by means of a FERC-approved tariff commonly referred to as the Interchange Agreement) for redispatch provided from 2002 to 2009. MISO asked the FERC to direct PJM to pay the underpaid amount, plus interest. In April 2010, PJM filed a complaint against MISO, alleging that MISO dispatched generation in the MISO region improperly under the RTO Joint Operating Agreement, and requested that the FERC order MISO to pay PJM up to $25 million. Xcel Energy intervened in the complaint proceedings in support of MISO. Informal settlement discussions have failed to resolve the issues, and the FERC issued an order setting the disputes for hearing and formal settlement discussions. Settlement discussions are continuing. The outcome of the complaint proceedings is uncertain. If MISO were to prevail, NSP-Minnesota and NSP-Wisconsin could receive a portion of the payments to MISO from PJM. If PJM were to prevail, NSP-Minnesota and NSP-Wisconsin could be required to reimburse MISO for a portion of the payments to PJM.

Southwest Power Pool, Inc. (SPP) Transmission Cost Recovery — The SPP transmission tariff currently establishes the mechanism for recovering costs associated with transmission projects. Currently, for base plan transmission projects, one-third of the costs are collected on an SPP region-wide basis and the remaining two-thirds are recovered from individual pricing zone(s) in SPP using a power flow analysis. For balanced portfolio projects, 100 percent of the costs are recovered on an SPP region-wide basis. In March 2010, the SPP board approved the tariff filing for this cost allocation methodology as follows:

- For projects rated at a voltage level less than 100 KV, all costs would be recovered from the pricing zone of the project;
- For projects rated at a voltage level between 100 KV and 300 KV, one-third of the costs would be recovered on an SPP region-wide basis and two-thirds would be recovered from the pricing zone of the project; and
- For projects rated at a voltage level greater than 300 KV, 100 percent of costs would be recovered on an SPP region-wide basis.

The FERC approved the SPP transmission cost allocation plan, effective June 2010. The SPP transmission cost allocation methodology will allow the costs of priority projects constructed in the SPS rate zone to be regionalized, but SPS will share in the costs of priority projects built in other SPP rate zones.

Electric Reliability Standards Compliance

Compliance Audits

On Oct. 31, 2008, the Western Electricity Coordinating Council (WECC) auditors issued their final audit report on PSCo's compliance with electric reliability standards. The report found a possible violation of one reliability standard related to relay maintenance.

In 2008, the NSP System, PSCo and SPS filed self-reports with the Midwest Reliability Organization (MRO), WECC and SPP regional entities, respectively, relating to failure to complete certain generation station battery tests, relay maintenance intervals and record keeping associated with certain critical infrastructure protection (CIP) standards. In 2009, the NSP System, PSCo, and SPS each reached agreement with the relevant regional entity that would resolve the PSCo open 2008 audit finding and the 2008 self reports by payment of a non-material penalty. These settlement agreements are pending approval at the NERC and will also be subject to FERC approval.

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In March 2010, the MRO, SPP and WECC conducted a joint compliance spot check to evaluate compliance with the NERC CIP standards, which were effective July 1, 2008. The draft non-public report issued by the three regional entities in July 2010 found that the Xcel Energy utility subsidiaries may not be in compliance with several of the CIP standards. Xcel Energy provided comments disagreeing with many of the conclusions of the draft report. The regional entity audit function issued a non-public final report in August 2010 alleging violations of certain CIP requirements, including certain violations common to all Xcel Energy utility subsidiaries; at that time, the spot check report was transferred to the MRO enforcement function. Xcel Energy continues to dispute the alleged violations and is working to resolve issues with the MRO enforcement functions. To what extent the regional entities or NERC may seek to impose penalties for violations of CIP standards is unknown at this time.

In July 2010, the WECC issued a non-public notice of alleged violation (NAV) related to (1) two alleged non-common CIP violations identified in the joint CIP spot-check, and (2) two violations self-reported by PSCo in February 2010 related to certain balancing authority (BAL) standards. The WECC NAV proposed a non-material penalty. PSCo requested that the proceedings be deferred to allow settlement negotiations to resolve the NAV. The matter is now in settlement discussions.

NERC Compliance Investigations

As a result of a series of transmission line outages, on Sept. 18, 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection. In addition, service to approximately 790 MW of load was temporarily interrupted, primarily in Saskatchewan, Canada. The initial transmission line outages occurred on the NSP System. In March 2008, NSP-Minnesota received notice that the MRO was commencing a compliance investigation of the September 2007 event. Because the event affected more than one region, the NERC took over the investigation. In January 2010, the NERC issued a preliminary report alleging the NSP System violated certain NERC reliability standards. The report represents the preliminary conclusions of the NERC and is subject to additional procedures at NERC, and ultimately FERC review. Xcel Energy disagrees with the many aspects of the preliminary report and filed its response with NERC in February 2010. The final outcome of the NERC compliance investigation, and whether and to what extent penalties for violations may be assessed, is unknown at this time.

In February 2010, the NERC notified NSP-Minnesota that it was commencing a non-public investigation of NSP-Minnesota maintenance practices associated with insulating oil levels in bulk electric system substations, as the result of an anonymous complaint received by the NERC. NSP-Minnesota is fully cooperating with the investigation. The final outcome of the NERC compliance investigation, and whether and to what extent NERC may seek to impose penalties for violations, is unknown at this time.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters at Note 7 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's Annual Report on Form 10-K for the year ended Dec. 31, 2009, 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, 2010, there have been no material changes to policies set forth in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009 except to the Employee Benefits Critical Accounting Policies and Estimates as follows:

Employee Benefits

Pension costs and funding requirements are expected to increase in the next few years as a result of significantly lower-than-expected investment returns in 2008. While investment returns exceeded the assumed levels from 2004-2006, and during 2009, investment returns in 2007 and 2008 were below the assumed levels. The investment gains or losses resulting from the difference between the expected pension returns and actual returns earned are deferred in the year the difference arises and are recognized over the expected average remaining years of service for active employees. Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects that the pension costs recognized for financial reporting purposes will increase from income of $3 million in 2008 and an expense of $13 million in 2009 to expense of $48 million in 2010 and expense of $71 million in 2011.

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While Xcel Energy currently projects no minimum required funding obligations for 2010, it anticipates a voluntary contribution of approximately $35 million to one of its pension plans by Dec. 31, 2010. At this time, pension funding contributions for 2011, which will be dependent on several factors including liquidity, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $125 million to $175 million. For future years, we anticipate contributions will be made to avoid benefit restrictions and at-risk status.

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 and its subsidiaries are exposed to a variety of market risks as disclosed in Management's Discussion and Analysis and in item 1A – Risk Factors in its Annual Report on Form 10-K for the year ended Dec. 31, 2009. 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. Market risks associated with derivatives are discussed in further detail in Note 10 to the consolidated financial statements.

Xcel Energy is exposed to the impact of changes in price for energy and energy related products, which is partially mitigated by Xcel Energy's use of commodity derivatives. Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning trust fund, master pension and postretirement health care plan trusts, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash. As of Sept. 30, 2010, there have been no material changes to market risks from that set forth in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2009.

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

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

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)	2010	2009
	$ 9,628	$ 4,169

Fair value of commodity trading net contract assets outstanding at Jan. 1						
Contracts realized or settled during the period		(4,282	)		(14,499	)
Commodity trading contract additions and changes during period		14,494			17,254	
Fair value of commodity trading net contract assets outstanding at Sept. 30	$	19,840		$	6,924	

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At Sept. 30, 2010, the fair values by source for the commodity trading net asset balance were as follows:

		Futures / Forwards				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$4,601	$12,225	$1,295	$146	$18,267
	2	(5)	-	-	-	(5)
PSCo	1	372	1,409	-	-	1,781
	2	-	-	-	-	-
		$4,968	$13,634	$1,295	$146	$20,043

		Options				
(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 Options Fair Value
NSP-Minnesota	2	$(203)	$-	$-	$-	$(203)
		$(203)	$-	$-	$-	$(203)

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

2 — Prices based on models and other valuation methods. These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the models.

Normal purchases and sales transactions, as defined by ASC 815 Derivatives and Hedging, non-trading activity such as hedged transactions and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations.

At Sept. 30, 2010, a 10 percent increase in market prices over the next 12 months for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.7 million.

Xcel Energy's short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts, and obligations over a particular period of time under normal market conditions. The VaRs for 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

2010	$	0.43	$	3.00	$	0.25	$	0.64	$	0.06
2009		0.46		5.00		0.45		1.51		0.16

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

At Sept. 30, 2010, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $1.1 million annually, or approximately $0.3 million per quarter. See Note 10 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries' interest rate derivatives.

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Xcel Energy also maintains trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At Sept. 30, 2010, these trust funds were invested in a diversified portfolio of debt and equity securities, commingled funds, and international equity funds. These trust funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an impact on earnings.

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

At Sept. 30, 2010, a 10 percent increase in prices would have resulted in a net decrease in credit exposure of $3.8 million, while a decrease of 10 percent would have resulted in an increase in credit exposure of $13.8 million.

Xcel Energy and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and other termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. 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. Note 10 to the consolidated financial statements describes the fair value hierarchy and discloses the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Sept. 30, 2010. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. 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 the commission approved regulatory recovery mechanism. 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, 2010.

Commodity derivative assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long-term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent immaterial percentages of total assets and liabilities measured at fair value at Sept. 30, 2010.

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 include $5.3 million and $1.1 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2010.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 commodity forwards and options held at Sept. 30, 2010.

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Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities; however, less observable and subjective inputs are often significant to these valuations, including risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated prepayments. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $98.9 million in the nuclear decommissioning fund at Sept. 30, 2010 (approximately 7.2 percent of total assets measured at fair value), are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

Liquidity and Capital Resources

Cash Flows

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009
Cash provided by operating activities	$ 1,522	$ 1,629

Cash provided by operating activities decreased by $107 million for the first nine months of 2010, compared with the first nine months of 2009. The decrease was primarily the result of changes in working capital due to changes in inventories, accounts receivable and accrued unbilled revenues as a result of reduced cost of natural gas in 2010, partially offset by a pension contribution made in the third quarter of 2009.

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009
Cash used in investing activities	$ (1,521)	$ (1,294)

Cash used in investing activities increased by $227 million for the first nine months of 2010, compared with the first nine months of 2009. Higher capital expenditures, primarily at NSP-Minnesota, NSP-Wisconsin and SPS were mainly offset by lower capital expenditures at PSCo.

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	2010	2009
Cash provided by (used in) financing activities	$ 103	$ (492)

Cash provided by financing activities increased by $595 million for the first nine months of 2010, compared with the first nine months of 2009. The increase is primarily due to higher proceeds from the issuance and lower repayments of long-term debt, partially offset by higher repayments of short-term borrowings.

Capital Requirements

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

Regulation of Derivatives — In July 2010, President Obama signed financial reform legislation which will regulate 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. 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 as well as result in extensive margin and fee requirements. Additionally there may be material increased reporting requirements. The bill contains provisions that should exempt certain derivatives end-users from much of the clearing and margining requirements. However, the CFTC is still developing the appropriate regulatory rules under the act and, at this time, it is not clear whether Xcel Energy will qualify for the exemption. If Xcel Energy does not meet the end-user exception, the margin requirements could be significant.

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. While Xcel Energy currently projects no minimum required funding obligations for 2010, it anticipates a voluntary contribution of approximately $35 million to one of its pension plans by Dec. 31, 2010. At this time, pension funding contributions for 2011, which will be dependent on several factors including liquidity, realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $125 million to $175 million. For future years, we anticipate contributions will be made to avoid benefit restrictions and at-risk status.

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Long-Term Contracts — In response to the CACJA passed in Colorado, PSCo has conducted a request for proposals for physical gas supply over a ten year period from Jan. 1, 2012 through 2021 for gas-fired generation. After reviewing several bids received in response to the Request for Proposal, PSCo has selected the winning bid. Pricing is based on a formula and given current input assumptions; the notional value of the deal over the duration of the contract is in excess of $700 million. The deal is contingent on CPUC approval of the transaction terms and conditions which must occur prior to Dec. 15, 2010.

Capital Sources

Settlement with Provident — In July 2010, Xcel Energy, PSCo and PSRI entered into a settlement agreement with Provident related to all claims asserted by Xcel Energy, PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI program. Under the terms of the settlement, Xcel Energy, PSCo and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company. Xcel Energy, PSCo and PSRI recorded this settlement of $25 million, or approximately $0.05 of non-recurring earnings per share, in the third quarter of 2010. The $25 million proceeds are not subject to income taxes. Xcel Energy does not consider this settlement to be part of ongoing earnings, as it is not expected to recur in the future.

Small Business Jobs Act of 2010 — On Sept. 27, 2010, President Obama signed into law the Small Business Jobs Act of 2010, which contains a tax incentive package that includes a one-year extension through 2010 of 50 percent bonus depreciation for businesses of all sizes. It extends for one additional year the 50 percent bonus depreciation provision first enacted in the Economic Stimulus Act of 2008 and subsequently renewed in the American Recovery and Reinvestment Act of 2009. The provision had expired at the end of 2009. Under the bonus depreciation provision, 50 percent of the basis of qualified property may be deducted in the year the property is placed in service and the remaining 50 percent recovered under normal depreciation rules. The accounting impacts of the provision, retroactive to Jan. 1, 2010 were reflected in the third quarter of 2010.

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

Short-Term Investments — Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Sept. 30, 2010, approximately $142.7 million of cash was held in these liquid operating accounts.

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

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

Credit Facilities — As of Oct. 20, 2010, Xcel Energy and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility	Drawn(a)	Available	Cash	Liquidity	Maturity
NSP-Minnesota	$ 482.2	$ 5.3	$ 476.9	$ 56.8	$ 533.7	December 2011
PSCo	675.1	4.5	670.6	19.1	689.7	December 2011

SPS	247.9	-	247.9	4.3	252.2	December 2011
Xcel Energy – Holding Company	771.6	47.1	724.5	0.8	725.3	December 2011
NSP-Wisconsin(b)	-	-	-	13.2	13.2	
Total	$ 2,176.8	$ 56.9	$ 2,119.9	$ 94.2	$ 2,214.1	

(a) Includes direct borrowings, outstanding commercial paper and letters of credit.
(b) NSP-Wisconsin does not have a separate credit facility; however, it has a borrowing agreement with NSP-Minnesota.

Xcel Energy intends to review it's credit facilities prior to expiration.

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 from the utility subsidiaries and investments from the Holding Company to the utility subsidiaries at market-based interest rates. The money pool balances are eliminated during consolidation.

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The utility money pool arrangement does not allow the Holding Company to borrow from the utilities. 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.

Equity Forward Agreements — In August 2010, Xcel Energy entered into equity forward agreements in connection with a public offering of 19 million shares of Xcel Energy common stock. Under the equity forward agreements (Forward Agreements), Xcel Energy agreed to issue to the banking counterparty 21.85 million shares of its common stock, including an over allotment of 2.85 million shares.

The forward price used to determine cash proceeds due Xcel Energy at settlement of the equity forward instruments underlying the Forward Agreements will be calculated based on the August 2010 public offering price of Xcel Energy's common stock, adjusted for underwriting fees, as well as the federal funds rate, less a spread of 0.50 percent, and expected dividends on Xcel Energy's common stock during the period the instruments are outstanding. Xcel Energy may settle the equity forward instruments at any time up to the maturity date of May 15, 2011. Xcel Energy may also unilaterally elect cash or net share settlement for any date up to maturity, for all or a portion of the equity forward instruments. Note 14 to the consolidated financial statements contains further information regarding the accounting for the equity forward instruments.

Xcel Energy expects to settle the forward equity agreement by physically delivering the 21.85 million shares of common equity in the fourth quarter of 2010.

Registration Statements — Xcel Energy's articles of incorporation authorize the issuance of one billion shares of common stock. As of Sept. 30, 2010 and Dec. 31, 2009, Xcel Energy had approximately 460 million shares and 458 million shares of common stock outstanding, respectively. In addition, Xcel Energy's articles of incorporation authorize the issuance of seven million shares of $100 par value preferred stock. On Sept. 30, 2010 and Dec. 31, 2009, Xcel Energy had approximately one million shares of preferred stock outstanding. Xcel Energy and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy has an effective automatic shelf registration statement that does not contain a limit on issuance capacity; however, Xcel Energy's ability to issue securities is limited by authority granted by the Board of Directors, which authority currently authorizes the issuance of up to an additional $950 million of debt and common equity securities. Assuming physical settlement of the forward sale contract that Xcel Energy entered into in August 2010, this issuance authority would be reduced by approximately $470 million.
- NSP-Minnesota has $200 million of debt securities available under its currently effective registration statement.
- PSCo has an automatic shelf registration statement filed on October 2010 that does not contain a limit on issuance capacity. However, PSCo's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to $1.8 billion of debt securities.
- NSP-Wisconsin has $50 million of debt securities remaining under its currently effective registration statement.

Long-Term Borrowings — See a discussion of the long-term borrowings in Note 9 to the consolidated financial statements.

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. In addition to the periodic issuance and repayment of short-term debt, Xcel Energy and its utility subsidiaries' financing plans are as follows:

- In May 2010, Xcel Energy issued $550 million of 10-year unsecured debt with a coupon of 4.7 percent.

- In August 2010, NSP-Minnesota issued $250 million of five-year first mortgage bonds with a coupon of 1.95 percent and $250 million of 30-year first mortgage bonds with a coupon of 4.85 percent.
- In August 2010, Xcel Energy entered into a forward equity sales agreement to issue 21.85 million shares of common stock.
- PSCo plans to issue approximately $400 million of first mortgage bonds in the fourth quarter of 2010.
- Xcel Energy also anticipates issuing approximately $75 million of equity through the Dividend Reinvestment Program and various benefit programs in 2010.

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

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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 2010 ongoing earnings guidance is $1.55 to $1.65 per share and expects earnings to be in the upper half of the range. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the rest of the year.
- Weather-adjusted retail electric utility sales increase approximately 1.2 to 1.4 percent.
- Weather-adjusted retail firm natural gas sales increase approximately 0 percent to 1 percent.
- Increased revenue due to the full year impact of 2009 electric rate cases in Colorado, Texas and New Mexico, along with the 2010 electric rate increases in Colorado.
- Constructive outcomes in all regulatory proceedings.
- Increased rider revenue recovery of approximately $30 million.
- O&M expenses are projected to increase approximately 8 percent to 9 percent.
- Depreciation expense is projected to increase $35 million to $45 million.
- Interest expense is projected to increase approximately $20 million to $30 million.
- AFUDC — equity is projected to decrease approximately $20 million.
- The effective tax rate is approximately 35 percent to 37 percent.
- Average common stock and equivalents total approximately 465 million shares.

Xcel Energy's 2011 ongoing earnings guidance is $1.65 to $1.75 per share. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales, adjusted for the sale of the Lubbock distribution assets, grow approximately 1 percent.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Constructive outcomes in all rate case and regulatory proceedings.
- Increased rider revenue recovery of approximately $35 million.
- O&M expenses are projected to increase 3 percent to 4 percent.
- Depreciation expense is projected to increase $55 million to $65 million.
- Interest expense is projected to increase approximately $30 million to $40 million.
- AFUDC — equity is projected to be relatively flat.
- The effective tax rate is approximately 35 percent to 37 percent.
- Average common stock and equivalents total approximately 485 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 the 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, 2010, 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. After consultation with legal counsel, Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

See Notes 6 and 7 to the consolidated financial statements in this Quarterly Report on Form 10-Q for further discussion of legal proceedings, including Regulatory Matters and Commitments and Contingent Liabilities, which are hereby incorporated by reference. Reference also is made to Item 3 and Notes 16 and 17 of Xcel Energy's consolidated financial statements in its Annual Report on Form 10-K for the year ended Dec. 31, 2009 for a description of certain legal proceedings presently pending.

Item 1A — RISK FACTORS

Except to the extent updated or described below, Xcel Energy'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, 2009, which is incorporated herein by reference.

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

Legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk. Increased public awareness and concern may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHG, and federal legislation has been introduced in both houses of Congress. Our electric generating facilities are likely to be subject to regulation under climate change laws introduced at either the state or federal level within the next few years.

The EPA has taken steps to regulate GHGs under the CAA. On Dec. 7, 2009, the EPA issued a finding that GHG emissions endanger public health and welfare, and that motor vehicle emissions contribute to the GHGs in the atmosphere. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty motor vehicles. The EPA finalized GHG efficiency standards for light duty vehicles in spring 2010 and has promulgated permitting requirements for GHGs for large new and modified stationary sources, such as power plants. These regulations will become applicable in 2011. We are also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in Note 7, Commitments and Contingent Liabilities, in the notes to the consolidated financial statements. While we believe such lawsuits are without merit, an adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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Many of the federal and state climate change legislative proposals, such as the American Clean Energy and Security Act and the proposed Kerry-Lieberman legislation, use a cap and trade policy structure, in which GHG emissions from a broad cross-section of the economy would be subject to an overall cap. Under the proposals, the cap becomes more stringent with the passage of time. The proposals establish mechanisms for GHG sources, such as power plants, to obtain "allowances" or permits to emit GHGs during the course of a year. The sources may use the allowances to cover their own emissions or sell them to other sources that do not hold enough emission allowances for their own operations. Proponents of the cap and trade policy believe it will result in the most cost effective, flexible emission reductions. There are many uncertainties, however, regarding when and in what form climate change legislation will be enacted. The impact of legislation and regulations, including a cap and trade structure, on us and our customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the United States, any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not recover all costs related to complying with regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

Item 6 — EXHIBITS

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* Indicates incorporation by reference
t Furnished, herewith, not filed. Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

1.01* Confirmations dated Aug. 3, 2010 and Aug. 4, 2010, between Xcel Energy and Bank of America, NA (Exhibits 1.01 and 1.02 to Form 8-K dated Aug. 9, 2010 (file no. 001-03034)).

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

3.02* Restated By-Laws of Xcel Energy (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).

4.01* Supplemental Indenture dated as of Aug. 1, 2010 between NSP-Minnesota and The Bank of New York Mellon Trust Company, NA, as successor Trustee, creating $250,000,000 principal amount of 1.950% First Mortgage Bonds, Series due August 15, 2015 and $250,000,000 principal amount of 4.850% First Mortgage Bonds, Series due Aug. 15, 2040. (Exhibit 4.01 to Form 8-K dated Aug. 11, 2010 (file no. 001-31387)).

31.01 Principal Executive Officer's and 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 t	The following materials from Xcel Energy's Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2010 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Cash Flow, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Stockholder's Equity and Comprehensive Income, (v) Notes to Condensed Consolidated Financial Statements, and (vi) 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.
(Registrant)

Oct. 29, 2010

By: /s/ TERESA S. MADDEN
Teresa S. Madden
Vice President and Controller
(Principal Accounting Officer)

/s/ DAVID M. SPARBY
David M. Sparby
Vice President and Chief Financial Officer
(Principal Financial Officer)