XCEL ENERGY INC
Form 10-Q
July 30, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

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

(612) 330-5500

(Registrant s telephone number, including area code)

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

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). x Yes o No

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

Large accelerated filer x	Accelerated filer £
Non-accelerated filer £ (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 x No

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 July 19, 2010
Common Stock, $2.50 par value	459,640,918 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 June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating revenues				
Electric	$ 2,040,702	$ 1,733,695	$ 4,036,294	$ 3,620,252
Natural gas	249,410	265,884	1,039,560	1,054,560
Other	17,652	16,504	39,372	36,813
Total operating revenues	2,307,764	2,016,083	5,115,226	4,711,625
Operating expenses				
Electric fuel and purchased power	986,088	797,101	1,974,566	1,721,849
Cost of natural gas sold and transported	126,963	146,388	708,076	738,153
Cost of sales other	4,704	3,987	12,396	9,353
Other operating and maintenance expenses	516,640	472,401	997,613	944,295
Conservation and demand side management program expenses	55,551	41,417	113,590	86,636
Depreciation and amortization	211,506	202,348	417,632	411,063
Taxes (other than income taxes)	81,008	73,073	162,384	150,111
Total operating expenses	1,982,460	1,736,715	4,386,257	4,061,460
Operating income	325,304	279,368	728,969	650,165
Other income, net	1,709	3,019	2,684	5,371
Equity earnings of unconsolidated subsidiaries	7,362	3,255	14,763	6,397
Allowance for funds used during construction equity	12,996	18,720	26,286	36,947
Interest charges and financing costs				
Interest charges includes other financing costs of $5,146, $5,114, $10,157 and $10,152, respectively	141,455	139,297	285,285	281,100
Allowance for funds used during construction debt	(6,575)	(9,845)	(14,312)	(20,073)
Total interest charges and financing costs	134,880	129,452	270,973	261,027
Income from continuing operations before income taxes	212,491	174,910	501,729	437,853
Income taxes	76,866	57,846	198,764	144,971
Income from continuing operations	135,625	117,064	302,965	292,882
Income (loss) from discontinued operations, net of tax	4,151	43	3,929	(1,708)
Net income	139,776	117,107	306,894	291,174

Dividend requirements on preferred stock		1,060		1,060		2,120		2,120
Earnings available to common shareholders	$	138,716	$	116,047	$	304,774	$	289,054
Weighted average common shares outstanding:								
Basic		460,041		456,307		459,483		455,753
Diluted		460,432		456,766		460,068		456,362
Earnings per average common share basic:								
Income from continuing operations	$	0.29	$	0.25	$	0.65	$	0.63
Income from discontinued operations		0.01				0.01		
Earnings per share	$	0.30	$	0.25	$	0.66	$	0.63
Earnings per average common share diluted:								
Income from continuing operations	$	0.29	$	0.25	$	0.65	$	0.63
Income from discontinued operations		0.01				0.01		
Earnings per share	$	0.30	$	0.25	$	0.66	$	0.63
Cash dividends declared per common share	$	0.25	$	0.25	$	0.50	$	0.48

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)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating activities		
Net income	$ 306,894	$ 291,174
Remove (income) loss from discontinued operations	(3,929)	1,708
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	421,820	419,841
Conservation and demand side management program expenses	15,514	13,904
Nuclear fuel amortization	49,551	37,713
Deferred income taxes	138,133	146,903
Amortization of investment tax credits	(3,188)	(3,475)
Allowance for equity funds used during construction	(26,286)	(36,947)
Equity earnings of unconsolidated subsidiaries	(14,763)	(6,397)
Dividends from unconsolidated subsidiaries	15,791	13,473
Share-based compensation expense	16,470	17,944
Net realized and unrealized hedging and derivative transactions	(21,374)	51,388
Changes in operating assets and liabilities:		
Accounts receivable	72,912	190,491
Accrued unbilled revenues	140,035	264,308
Inventories	101,822	229,504
Recoverable purchased natural gas and electric energy costs	(1,186)	(31,891)
Other current assets	21,491	1,695
Accounts payable	(226,316)	(310,589)
Net regulatory assets and liabilities	28,829	32,886
Other current liabilities	(119,096)	(43,239)
Change in other noncurrent assets	(2,736)	5,898
Change in other noncurrent liabilities	(22,218)	(157,191)
Operating cash flows provided by (used) in discontinued operations	23,361	(3,335)
Net cash provided by operating activities	911,531	1,125,766
Investing activities		
Utility capital/construction expenditures	(967,331)	(947,474)
Allowance for equity funds used during construction	26,286	36,947
Purchase of investments in external decommissioning fund	(3,001,198)	(1,014,130)
Proceeds from the sale of investments in external decommissioning fund	3,006,616	1,012,705
Investment in WYCO Development LLC	(2,905)	(25,254)
Change in restricted cash	(44)	33
Other investments	4,150	3,537
Net cash used in investing activities	(934,426)	(933,636)
Financing activities		
Repayment of short-term borrowings, net	(330,000)	(85,250)
Proceeds from issuance of long-term debt	544,205	394,897
Repayment of long-term debt, including reacquisition premiums	(25,860)	(168,971)
Proceeds from issuance of common stock	4,294	2,665
Dividends paid	(212,387)	(203,859)
Net cash used in financing activities	(19,748)	(60,518)

Net (decrease) increase in cash and cash equivalents		(42,643)		131,612
Net increase (decrease) in cash and cash equivalents discontinued operations		842		(557)
Cash and cash equivalents at beginning of period		107,789		249,198
Cash and cash equivalents at end of period	$	65,988	$	380,253
Supplemental disclosure of cash flow information:				
Cash paid for interest, net of amounts capitalized	$	(254,113)	$	(250,990)
Cash paid for income taxes, net		(7,831)		(26,569)
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	53,871	$	37,066
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	32,261	$	36,076

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(amounts in thousands of dollars)

	June 30, 2010	Dec. 31, 2009
Assets		
Current assets		
Cash and cash equivalents	$ 65,988	$ 107,789
Accounts receivable, net	662,461	729,409
Accrued unbilled revenues	554,014	694,049
Inventories	464,383	566,205
Recoverable purchased natural gas and electric energy costs	57,930	56,744
Derivative instruments valuation	63,905	97,700
Prepayments and other	305,275	359,560
Current assets related to discontinued operations	89,991	151,955
Total current assets	2,263,947	2,763,411
Property, plant and equipment, net	19,074,194	18,508,296
Other assets		
Nuclear decommissioning fund and other investments	1,376,601	1,381,791
Regulatory assets	2,297,485	2,287,636
Derivative instruments valuation	260,094	289,530
Other	151,714	140,367
Noncurrent assets related to discontinued operations	139,177	117,397
Total other assets	4,225,071	4,216,721
Total assets	$ 25,563,212	$ 25,488,428
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 545,637	$ 543,814
Short-term debt	129,000	459,000
Accounts payable	842,277	1,083,127
Taxes accrued	166,742	232,964
Accrued interest	161,436	157,253
Dividends payable	117,115	113,147
Derivative instruments valuation	52,150	46,554
Other	322,361	350,318
Current liabilities related to discontinued operations	8,949	29,080
Total current liabilities	2,345,667	3,015,257
Deferred credits and other liabilities		
Deferred income taxes	3,448,079	3,336,354
Deferred investment tax credits	96,102	99,290
Regulatory liabilities	1,196,628	1,222,833
Asset retirement obligations	905,542	881,479
Derivative instruments valuation	293,857	307,770
Customer advances	281,302	295,470
Pension and employee benefit obligations	830,913	838,067
Other	254,895	211,666
Noncurrent liabilities related to discontinued operations	3,610	3,389

Total deferred credits and other liabilities		7,310,928		7,196,318
Commitments and contingent liabilities				
Capitalization				
Long-term debt		8,409,815		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: June 30, 2010 459,627,420; Dec. 31, 2009 457,509,263		7,391,822		7,283,245
Total liabilities and equity	$	25,563,212	$	25,488,428

See Notes to Consolidated Financial Statements

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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		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
	Shares	Par Value				
Three Months Ended June 30, 2010 and 2009						
Balance at March 31, 2009	455,256	$ 1,138,141	$ 4,710,666	$ 1,252,471	$ (52,196)	$ 7,049,082
Net income				117,107		117,107
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $255					372	372
Net derivative instrument fair value changes during the period, net of tax of $1,379					2,131	2,131
Unrealized gain - marketable securities, net of tax of $232					339	339
Comprehensive income for the period						119,949
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(112,113)		(112,113)
Issuances of common stock	461	1,151	9,347			10,498
Share-based compensation			7,367			7,367
Balance at June 30, 2009	455,717	$ 1,139,292	$ 4,727,380	$ 1,256,405	$ (49,354)	$ 7,073,723
Balance at March 31, 2010	459,215	$ 1,148,038	$ 4,784,152	$ 1,472,308	$ (48,627)	$ 7,355,871
Net income				139,776		139,776
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $321					456	456
Net derivative instrument fair value changes during the period, net of tax of $(2,725)					(3,807)	(3,807)
Unrealized loss - marketable securities, net of tax of $(74)					(107)	(107)
Comprehensive income for the period						136,318
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(117,027)		(117,027)
Issuances of common stock	412	1,031	7,612			8,643
Share-based compensation			9,077			9,077
Balance at June 30, 2010	459,627	$ 1,149,069	$ 4,800,841	$ 1,493,997	$ (52,085)	$ 7,391,822

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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
Six Months Ended June 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				291,174		291,174
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $509					741	741
Net derivative instrument fair value changes during the period, net of tax of $2,180					3,331	3,331
Unrealized gain - marketable securities, net of tax of $168					243	243
Comprehensive income for the period						295,489
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(220,560)		(220,560)
Issuances of common stock	1,925	4,812	18,065			22,877
Share-based compensation			14,296			14,296
Balance at June 30, 2009	455,717	$ 1,139,292	$ 4,727,380	$ 1,256,405	$ (49,354)	$ 7,073,723
Balance at Dec. 31, 2009	457,509	$ 1,143,773	$ 4,769,980	$ 1,419,201	$ (49,709)	$ 7,283,245
Net income				306,894		306,894
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $616					875	875
Net derivative instrument fair value changes during the period, net of tax of $(2,265)					(3,155)	(3,155)
Unrealized loss - marketable securities, net of tax of $(66)					(96)	(96)
Comprehensive income for the period						304,518
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(229,978)		(229,978)
Issuances of common stock	2,118	5,296	15,633			20,929
Share-based compensation			15,228			15,228
Balance at June 30, 2010	459,627	$ 1,149,069	$ 4,800,841	$ 1,493,997	$ (52,085)	$ 7,391,822

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 June 30, 2010 and Dec. 31, 2009; the results of its operations and changes in stockholders equity for the three and six months ended June 30, 2010 and 2009; and its cash flows for the six months ended June 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 June 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 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 six months ended June 30, 2009 were reclassified as a separate 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) are 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)		June 30, 2010		Dec. 31, 2009
Accounts receivable, net				
Accounts receivable	$	712,244	$	785,512
Less allowance for bad debts		(49,783)		(56,103)
	$	662,461	$	729,409
Inventories				
Materials and supplies	$	182,091	$	172,993
Fuel		184,337		221,457
Natural gas		97,955		171,755
	$	464,383	$	566,205
Property, plant and equipment, net				
Electric plant	$	23,745,491	$	22,589,071
Natural gas plant		3,336,052		3,269,934
Common and other property		1,532,921		1,492,463
Construction work in progress		1,360,506		1,769,545
Total property, plant and equipment		29,974,970		29,121,013
Less accumulated depreciation		(11,208,797)		(10,914,509)
Nuclear fuel		1,793,249		1,737,469
Less accumulated amortization		(1,485,228)		(1,435,677)
	$	19,074,194	$	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)		June 30, 2010		Dec. 31, 2009
Cash	$	8,701	$	7,859
Deferred income tax benefits		48,453		106,770
Other current assets		32,837		37,326
Current assets related to discontinued operations	$	89,991	$	151,955
Deferred income tax benefits	$	121,067	$	95,424
Other noncurrent assets		18,110		21,973
Noncurrent assets related to discontinued operations	$	139,177	$	117,397
Accounts payable	$	325	$	445
Other current liabilities		8,624		28,635
Current liabilities related to discontinued operations	$	8,949	$	29,080

Noncurrent liabilities related to discontinued operations	$ 3,610	$ 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, 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), or $0.02 per share during the first quarter of 2010. Xcel Energy anticipates that the Tax Court proceedings will be dismissed in 2010.

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, or $0.04 per share, of previously recognized tax benefits relating to Medicare Part D subsidies during the first quarter of 2010. Xcel Energy does not expect the $17 million of additional tax expense to recur in future periods. 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 expires on Aug. 28, 2010. The IRS audit of tax years 2008 and 2009 is expected to begin during the fourth quarter of 2010.

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 June 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	2004
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.

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.

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

(Millions of Dollars)	June 30, 2010	Dec. 31, 2009
Unrecognized tax benefit - Permanent tax positions	$ 4.0	$ 4.0
Unrecognized tax benefit - Temporary tax positions	22.6	19.7
Unrecognized tax benefit balance	$ 26.6	$ 23.7

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

(Millions of Dollars)	June 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 as reported in continuing operations and discontinued operations were as follows:

(Millions of Dollars)	June 30, 2010	Dec. 31, 2009
Continuing operations	$ (8.8)	$ (8.9)
Discontinued operations	(13.7)	(20.4)

The increase in the unrecognized tax benefit balance reported in continuing operations of $1.8 million from March 31, 2010 to June 30, 2010 and $2.9 million from Dec. 31, 2009 to June 30, 2010 was due primarily to the addition of similar uncertain tax positions related to ongoing activity. Xcel Energy s amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months when the IRS and state audits resume. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

The decrease in the unrecognized tax benefit balance reported in discontinued operations of $6.3 million from March 31, 2010 to June 30, 2010 and Dec. 31, 2009 to June 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 for 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 reported in 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)

Interest expense related to unrecognized tax benefits for the three months ended March 31		(0.1)		(0.3)
Interest expense related to unrecognized tax benefits for the three months ended June 30		(0.3)		
Payable for interest related to unrecognized tax benefits at June 30	$	(0.8)	$	(2.2)

A reconciliation of the beginning and ending amount of the receivable for interest related to unrecognized tax benefits reported in 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
Receivable for interest related to unrecognized tax benefits at June 30	$	0.5	$	1.8

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

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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.

In May 2010, the Office of Energy Security (OES) filed direct testimony recommending a rate increase of $1.8 million based on a 9.67 percent ROE. The Minnesota Office of Attorney General (OAG) made several adjustments. In addition to ROE, both parties focused on adjustments to bad debt expense, distribution operating and maintenance expenses (O&M), cost of debt and pension expense.

Evidentiary hearings were held in June 2010. By the end of the hearings, NSP-Minnesota made several adjustments to reflect more recent information, accepted the OES position on distribution O&M, and is currently seeking an increase of $10.0 million based on a 10.6 percent ROE. The 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 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 continues to recommend further adjustments in bad debt expense, distribution O&M and the cost of debt.

The remaining procedural schedule is listed as follows:

- Reply briefs and proposed findings due Aug. 19, 2010; and
- Administrative law judge (ALJ) report due Oct. 1, 2010.

A decision from the MPUC in this proceeding is expected 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. On April 27, 2010, the MPUC approved the 2010 TCR rider that will recover approximately $10.8 million in 2010, including initial costs associated with three of the four CapX 2020 transmission projects. The MPUC did not allow 2010 recovery of $1.2 million in costs associated with the Brookings, S.D.-Hampton, Minn. CapX 2020 transmission line because of uncertainty regarding cost allocation as the result of impending Midwest Independent Transmission System Operator, Inc. (MISO) tariff changes. NSP-Minnesota filed a request to reconsider the MPUC s determination regarding the Brookings S. D. project. The reconsideration request is pending MPUC action. MISO filed the proposed cost allocation tariff changes with the Federal Energy Regulatory Commission (FERC) on July 15, 2010. The MPUC also expressed a desire to limit TCR to the initial project cost estimates and address any potential additional amounts in general rate cases. This approach to rider administration does not impact the 2010 TCR request.

Renewable Energy Standard (RES) Rider The MPUC has approved a rider to recover the costs for utility-owned projects implemented in compliance with the Minnesota RES. On April 1, 2010, the MPUC approved the 2010 RES rider that will result in $45.6 million in revenue. As noted with the TCR rider above, the MPUC also expressed a desire to limit recovery based on initial project estimates and address any potential additional amounts in general rate cases. This approach to rider administration is not expected to have a material impact in 2010.

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Annual Automatic Adjustment Report for 2008/2009 In September 2009, NSP-Minnesota filed its annual electrical 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). On June 18, 2010, the OES filed comments recommending approval of the 2008/2009 natural gas automatic adjustment report. Final MPUC action is pending. Comments on NSP-Minnesota s 2009 electric report are due in January 2011. 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.

NSP-Wisconsin

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

2009 Electric Fuel Cost Recovery In April 2009, the PSCW initiated a fuel cost recovery proceeding under the Wisconsin fuel rules and set NSP-Wisconsin s rates subject to refund with interest, pending a full review of 2009 fuel costs. The PSCW completed its review of actual 2009 fuel costs in the second quarter of 2010 and determined that NSP-Wisconsin s 2009 fuel refund obligation was $19.1 million. In NSP-Wisconsin s 2010 rate case decision, the PSCW authorized NSP-Wisconsin to apply $6.4 million of the 2009 fuel refund obligation to offset the 2010 Wisconsin retail electric rate increase. NSP-Wisconsin implemented fuel cost credits in the first half of 2010 designed to refund the remaining $12.7 million to customers.

2010 Electric Fuel Cost Recovery NSP-Wisconsin s fuel and purchased power costs through March 2010 were approximately $1.7 million, or 4.1 percent lower than authorized in the 2010 electric rate case, which was outside the monthly and cumulative variance ranges for monitored fuel costs established by the PSCW. Pursuant to the fuel rules, on May 11, 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. However, through June 2010, NSP-Wisconsin s fuel costs were approximately $0.2 million, or 0.2 percent, lower than authorized in the 2010 electric rate case, which is within the cumulative variance range for monitored fuel costs established by the PSCW.

2010 Electric Rate Case Reopener As part of the resolution of its 2010 electric rate case, the PSCW allowed NSP-Wisconsin to file for a reopener for production and transmission capital costs, as well as fuel and purchased power expense. NSP-Wisconsin is expected to file its reopener petition in August 2010.

PSCo

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

Base Rate

PSCo 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 will be implemented:

- A rate increase of $67 million was implemented on Jan. 1, 2010. The adjustments to the rate increase, because of the delay of the in-service date of Comanche Unit 3, include reduced O&M, property taxes, the impact of a delay in changes to jurisdictional allocators and depreciation expenses;
- Base rates increased to recover $121 million annually, on May 14, 2010 when Comanche Unit 3 went into service; and
- Finally, base rates will increase to recover $128.3 million annually on Jan. 1, 2011 to reflect 2011 property taxes.

Several parties, including PSCo and the Office of Consumer Counsel (OCC), filed motions for reconsideration. On April 19, 2010, the CPUC granted PSCo s request to not include long-term debt interest in the working capital calculation, which increases the revenue deficiency, recovered under the order by approximately $2.2 million, and denied all other requests for reconsideration.

Comanche Unit 3 went into service in May 2010, and the CPUC allowed both the step change for Comanche Unit 3 in-service and the increase to reflect the debt interest on working capital.

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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. The CPUC also approved a low-income pilot program similar to the previously approved gas low-income pilot program.

Transmission Cost Adjustment (TCA) Rider In April 2010, PSCo filed a TCA rider, to adjust to 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.

Unreasonable Rates for Natural Gas Formal Complaint In July 2009, the trial advocacy staff of the CPUC proposed a complaint against PSCo for unreasonable rates for natural gas service associated with earnings in excess of PSCo s authorized return that occurred in 2008. In January 2010, the CPUC opened a proceeding and assigned this matter to an ALJ.

The ALJ recommended approval of an unopposed settlement of the case on June 14, 2010 and vacated the schedule in the docket. The settlement, provided that no adjustments to current rates would be made, PSCo would file a gas rate case before the end of 2010. In that case, PSCo would propose to remove recovery on gas in storage from base rates to an adjustment clause.

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 margins would be shared based on the following:

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.

Pending and Recently Concluded Regulatory Proceedings 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. In June and July 2010, PSCo filed blackbox settlements with all of its wholesale customers except for Intermountain Rural Electric Association at the FERC. Under the terms of that settlement, PSCo would increase rates on an annual basis by $17.0 million for these customers, effective July 7, 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 settlement provide for lower depreciation expense than requested and for certain capacity costs to be recovered through the fuel clause until those contracts expire. A decision by the FERC on the settlements is expected by the end of 2010.

SPS

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

Texas Retail Base Rate Case On May 17, 2010, SPS filed a Texas rate case with the PUCT, 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.

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The following table summarizes the request:

(Millions of Dollars)		Request
Proposed base rate increase	$	62.0
Franchise fee cost recovery		8.7
Nitrogen oxide (NOx) emission allowances		0.8
Purchased capacity recovery factor		(13.5)
Transmission cost recovery factor		(4.6)
Adjusted rate increase	$	53.4
ROE		11.35%
Equity ratio		51.0
Electric rate base	$	1,031

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.

SPS expects new rates to go into effect early in 2011, although fully litigated cases would typically take longer for rates to be implemented. The procedural schedule is as follows:

- Intervenor testimony due Sept. 16, 2010;
- Staff testimony due Sept. 23, 2010;
- SPS rebuttal testimony due Oct. 7, 2010; and
- Hearings are Oct. 19 through Nov. 5, 2010.

Lubbock Electric Distribution Assets In November 2009, SPS entered into an agreement with the city of Lubbock, Texas, in which SPS will sell its electric distribution system assets within the city limits to the City of Lubbock 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. This transaction is expected to close late in 2010. It is anticipated that any resulting gain on the sale of assets will be shared with retail customers in Texas, as determined in the above Texas retail base rate case.

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, the parties to the Texas proceeding filed an uncontested settlement resolving all issues in the Texas proceeding relating to the transaction. The PUCT has placed this matter on its agenda for its July 30, 2010 open meeting. Also in June 2010, SPS filed its application in New Mexico for approval of the transaction. A hearing examiner has adopted a procedural schedule for a hearing on Sept. 14, 2010.

Pending and Recently Concluded Regulatory Proceedings FERC

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). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to the complainants. Cap Rock Energy Corporation (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.

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In April 2008, the FERC issued its order on the complaint applied to the remaining non-settling parties. The order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006, for SPS full requirements customers who pay traditional cost-based rates and require certain refunds. Several parties, including SPS, filed requests for rehearing on the order. 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 June 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 and 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 regarding the same base rate and fuel issues raised in the complaint described above. 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 system average cost power purchases by 90 to 100 megawatts (MW) in 2012, and implement staged reductions in system average cost power purchases through the term of the agreement, which terminates on May 31, 2026. The settlement made the replacement contract contingent on certain state approvals. In the event not all state regulatory approvals are received, the settlement includes 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.

SPS reached settlements that would obtain the needed state approvals referenced above. No party has contested the PUCT approval, and it is expected that the PUCT will act on the settlement in August 2010. The New Mexico parties and NMPRC staff filed a stipulation to resolve the NMPRC proceeding. The hearing examiner heard the stipulation and recommended that the NMPRC approve the stipulation. The NMPRC is expected to consider a final order in August 2010. 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.

Cap Rock Complaint Settlement Cap Rock is an intervenor in the complaint case. In the second quarter of 2010, SPS and Cap Rock filed a settlement agreement with the FERC regarding the same base rate and fuel issues described above. 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 settlement agreement was also contingent on FERC and PUCT approval of the Sharyland acquisition of Cap Rock, which was approved in June 2010 and July 2010, respectively.

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.

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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 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.

Certain natural gas and biomass fueled purchased power agreements that either reimburse the independent power producing entities for fuel costs, or contain tolling arrangements under which Xcel Energy procures the fuel required to produce the energy it purchases, have been determined to be variable interest entities.

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 operations and maintenance, 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 June 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. SPS has evaluated the TUCO coal supply contracts and has concluded that it is not the primary beneficiary because SPS does not have the power to direct the activities that most significantly impact TUCO s economic performance.

Low-Income Housing Limited Partnerships Eloigne 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. It has been 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.

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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)		June 30, 2010		Dec. 31, 2009
Current assets	$	3,717	$	3,674
Property, plant and equipment, net		100,696		103,552
Other noncurrent assets		7,687		7,577
Total assets	$	112,100	$	114,803
Current liabilities	$	14,128	$	12,315
Mortgages and other long-term debt payable		52,027		54,927
Other noncurrent liabilities		8,140		8,250
Total liabilities	$	74,295	$	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 June 30, 2010, the liability for the cost of remediating these sites was estimated to be $102.0 million, of which $5.5 million 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.

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). The estimated remediation costs for the cleanup proposed by the EPA in the PRAP range between $94.4 million and $112.8 million. 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. It is expected that the EPA will select a final remedial action plan sometime later in

2010.

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 the EPA selects a remediation strategy for the entire site and determines NSP-Wisconsin s level of responsibility. NSP-Wisconsin continues to work with the Wisconsin Department of Natural Resources to 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 minimum of the range of remediation costs established by the PRAP, together with estimated outside legal, consultant and remedial design 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 sometime later in 2010.

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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

Colorado Clean Air-Clean Jobs Act The Colorado Clean Air-Clean Jobs Act (the Act) was signed into law on April 19, 2010. The Act establishes a timeline and regulatory framework for rate-regulated utilities in Colorado to develop a plan to potentially retrofit, retire or replace 900 MW or more of aging coal-fired electric generating capacity. The plan must result in a reduction of 70 to 80 percent in NOx emissions from affected coal-fired power plants by 2018 or sooner to meet current and reasonably foreseeable Clean Air Act (CAA) emission reduction mandates.

Under the emission reduction plan, PSCo may retrofit its existing coal-fired plants with emission controls or retire and replace the plants with natural gas-fired generation or other low emitting resources. The Act specifically requires PSCo to study the early retirement of up to 900 MW of existing coal-fired capacity, but does not require any retirement unless, among other things, the retirement can be accomplished at a reasonable cost while protecting system reliability. PSCo must submit its plan to the CPUC by Aug. 15, 2010 and the CPUC must act on the plan by Dec. 15, 2010.

Pursuant to the Act, PSCo is entitled to fully 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 any earnings deficiency, additional relief, including a more comprehensive rider to recover other plant costs such as depreciation and O&M expense, or a multi-year rate plan are allowed. The Act also makes interim rates permissible in Colorado, starting Jan. 1, 2012. Additional information regarding the Colorado Clean Air-Clean Jobs Act is presented in the Management s Discussion of Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Continuing Operations, Public Utility Regulation section.

EPA Greenhouse Gas (GHG) Rulemaking On Dec. 7, 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. This endangerment finding creates a mandatory duty for the EPA to regulate GHGs from light duty vehicles. The EPA finalized GHG efficiency standards for light duty vehicles in spring of 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.

Clean Air Interstate Rule (CAIR) In March 2005, the EPA issued the CAIR to further regulate sulfur dioxide (SO_2) and NOx emissions. The objective of CAIR is to cap emissions of SO_2 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. On July 6, 2010, the EPA issued the proposed Clean Air Transport Rule (CATR), which would replace CAIR by requiring SO_2 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 SO_2 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 $1.2 million. Annual purchases of SO_2 allowances are estimated in the range of $1.7 million to $7.7 million each year, beginning in 2013, for phase I. Allowance cost estimates for SPS are based on fuel quality and current market data. 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 $0.4 million. Allowance cost estimates for NSP-Wisconsin are based on fuel quality and current market data. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates. On Nov. 3, 2009, the EPA published a rule staying the effectiveness of CAIR in Minnesota effective Dec. 3, 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 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 CAMR. Xcel Energy anticipates that the EPA will require affected facilities to demonstrate compliance within 18 to 36 months thereafter.

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 is evaluating the emission controls required to meet the state rule for the remaining units and is currently unable to provide a total capital cost estimate.

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 has 180 days to either approve or disapprove the plan. 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 SO_2, NO_x and particulate matter emissions under BART and then set BART emissions limits for those facilities.

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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. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2012 and 2015. Colorado s BART state implementation plan (SIP) has been submitted to the EPA for approval. The Colorado Air Pollution Control Division (CAPCD) is currently analyzing what types of additional NOx controls may be necessary to meet reasonable progress goals for Colorado s Class I areas, the new ozone standard, and Rocky Mountain National Park nitrogen deposition reduction goals. The CAPCD has indicated that it expects to submit a Regional Haze/Reasonable Further Progress SIP to the EPA in early 2011. PSCo anticipates that for those plants included in the Clean Air-Clean Jobs Act s emission reduction plan, the plan will satisfy regional haze requirements.

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 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 SO_2 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 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. There is a 90-day comment deadline to submit comments on the rule, but requests for extension of time to submit comments have been submitted to the EPA. 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.

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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 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. SPS denies these allegations and is negotiating with the NMED regarding the alleged violations and proposed penalty prior to the issuance of a final order.

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. (eprime) 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 United States 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 and the matter is currently pending before the Missouri Supreme Court.

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*.

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Environmental Litigation

Carbon Dioxide (CO_2) Emissions Lawsuit 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 CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 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 CO_2 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. Defendants anticipate filing a petition for review with the U. S. Supreme Court.

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.

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. 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 projects undertaken at Xcel Energy s Sherco and Black Dog plants to determine whether these projects were carried out in compliance with the New Source Review. 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 documents related to projects that may be undertaken in the future at the plants. Xcel Energy believes that the request for future project information exceeds the EPA s CAA authority and serves no legitimate investigative purpose. The EPA s information-request authority is limited to information that is necessary and appropriate to determine whether or not Xcel Energy is in compliance with the CAA. Planned future projects, on which construction has not begun and which may never be implemented, cannot be the basis of a CAA violation. Xcel Energy believes that it has complied with its obligation to provide information and has filed a motion to dismiss the lawsuit.

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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.

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. 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 late 2011.

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Mallon vs. Xcel Energy Inc. In August 2007, Xcel Energy, PSCo and PSRI (Plaintiffs) commenced a lawsuit in Colorado state court against Theodore 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 Life & Accident Insurance Company (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.

On July 6, 2010, Plaintiffs entered into a settlement agreement with Provident. Under the terms of the settlement, Provident and Reassure America Life Insurance Company paid Plaintiffs $25 million. Xcel Energy will record this settlement of $25 million in the third quarter of 2010. See additional information set forth in Note 17 to the consolidated financial statements in this Quarterly Report on Form 10-Q.

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 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 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.

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 in excess of $55 million. 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. 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 June 2010, PSCo exercised its contractual right to draw on Shaw s letter of credit in the total amount of approximately $29.6 million. Trial is scheduled for Oct. 18, 2010.

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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. PSCo will file a response denying liability in due course.

8. Short-Term Borrowings and Other Financing Instruments

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

(Millions of Dollars)	June 30, 2010	Dec. 31, 2009
Commercial paper outstanding	$ 129	$ 459
Weighted average interest rate	0.41%	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 June 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.

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.

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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 June 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 June 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 six months ended June 30, 2010.

At June 30, 2010, accumulated OCI related to commodity derivative cash flow hedges included $1.7 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 June 30, 2010 and Dec. 31, 2009:

(Amounts in Thousands) (a)(b)	**June 30, 2010**	**Dec. 31, 2009**
Megawatt hours (MWh) of electricity	72,349	37,932
MMBtu of natural gas	57,930	57,181

Gallons of vehicle fuel	1,990	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.

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:

	Three Months Ended June 30,	
(Thousands of Dollars)	**2010**	**2009**
Accumulated other comprehensive loss related to cash flow hedges at April 1	$ (5,783)	$ (11,913)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(4,413)	1,270
After-tax net realized losses on derivative transactions reclassified into earnings	606	861
Accumulated other comprehensive loss related to cash flow hedges at June 30	$ (9,590)	$ (9,782)

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(Thousands of Dollars)	Six Months Ended June 30, 2010	2009
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (6,435)	$ (13,113)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(4,387)	1,160
After-tax net realized losses on derivative transactions reclassified into earnings	1,232	2,171
Accumulated other comprehensive loss related to cash flow hedges at June 30	$ (9,590)	$ (9,782)

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

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

	Three Months Ended June 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (7,210)	$	$ 260(a)	$	$
Vehicle fuel and other commodity	(365)		783(e)		
Total	$ (7,575)	$	$ 1,043	$	$
Other derivative instruments					
Trading commodity	$	$	$	$	$ 224(b)
Electric commodity		7,597		(2,111)(c)	
Natural gas commodity		(4,612)		752(d)	
Other					85(b)
Total	$	$ 2,985	$	$ (1,359)	$ 309

	Six Months Ended June 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (7,210)	$	$ 419(a)	$	$
Vehicle fuel and other commodity	(322)		1,693(e)		
Total	$ (7,532)	$	$ 2,112	$	$
Other derivative instruments					

Trading commodity	$	$	$	$	$ 5,605(b)
Electric commodity		(9,582)		(4,838)(c)	
Natural gas commodity		(40,706)		4,707(d)	
Other					135(b)
Total	$	$ (50,288)	$	$ (131)	$ 5,740

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	Three Months Ended June 30, 2009				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (632)	$	$ 336(a)	$	$
Electric commodity		957		(1,243)(c)	
Natural gas commodity		(417)		409(d)	
Vehicle fuel and other commodity	2,101		1,705(e)		
Total	$ 1,469	$ 540	$ 2,041	$ (834)	$
Other derivative instruments					
Interest rate	$	$	$	$	$ 1,252(a)
Trading commodity					674(b)
Electric commodity		45,079		(706)(c)	
Natural gas commodity		5,481			
Other					200(b)
Total	$	$ 50,560	$	$ (706)	$ 2,126

	Six Months Ended June 30, 2009				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		
(Thousands of Dollars)	Other Comprehensive Income (Losses)	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (632)	$	$ 635(a)	$	$
Electric commodity		(18,599)		(4,755)(c)	
Natural gas commodity		(17,287)		78,286(d)	(30,241)(d)
Vehicle fuel and other commodity	1,914		3,594(e)		
Total	$ 1,282	$ (35,886)	$ 4,229	$ 73,531	$ (30,241)
Other derivative instruments					
Interest rate	$	$	$	$	$ 2,008(a)
Trading commodity					4,067(b)
Electric commodity		43,342		(386)(c)	
Natural gas commodity		(9,166)		15(d)	
Other					200(b)
Total	$	$ 34,176	$	$ (371)	$ 6,275

(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 $3.4 million and $0.6 million of derivative instruments in a net liability position at June 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 $3.4 million and $3.4 million, respectively. At June 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 June 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 enhanced 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 June 30, 2010:

	June 30, 2010					
		Fair Value		Fair Value	Counterparty	
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Netting (c)**	**Total**
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$	$ 23	$	$ 23	$ (23)	$
Other derivative instruments:						
Trading commodity	2,211	35,135	237	37,583	(26,373)	11,210
Electric commodity		916	8,654	9,570	(3,728)	5,842
Natural gas commodity		145		145	(128)	17
Total current derivative assets	$ 2,211	$ 36,219	$ 8,891	$ 47,321	$ (30,252)	17,069
Purchased power agreements (b)						46,836
Current derivative instruments valuation						$ 63,905
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$	$ 83	$	$ 83	$	$ 83
Other derivative instruments:						
Trading commodity		18,279	7,661	25,940	(3,130)	22,810
Total noncurrent derivative assets	$	$ 18,362	$ 7,661	$ 26,023	$ (3,130)	22,893
Purchased power agreements (b)						237,201
Noncurrent derivative instruments valuation						$ 260,094
Other recurring fair value assets						
Nuclear decommissioning fund (a)						
Cash equivalents	$	$ 211,252	$	$ 211,252	$	$ 211,252
Debt securities:						
Government securities		198,365		198,365		198,365
U.S. corporate bonds		306,493		306,493		306,493
Foreign securities		2,152		2,152		2,152
Municipal bonds		79,114		79,114		79,114
Asset-backed securities			40,067	40,067		40,067
Mortgage-backed securities			65,059	65,059		65,059
Equity securities (common stock)	346,111			346,111		346,111
Total	$ 346,111	$ 797,376	$ 105,126	$ 1,248,613	$	$ 1,248,613

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	June 30, 2010					
		Fair Value		Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting (c)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$	$ 1,817	$	$ 1,817	$ (23)	$ 1,794
Other derivative instruments:						
Trading commodity	1,719	32,502	119	34,340	(31,506)	2,834
Electric commodity			3,728	3,728	(3,728)	
Natural gas commodity		32,035		32,035	(7,704)	24,331
Total current derivative liabilities	$ 1,719	$ 66,354	$ 3,847	$ 71,920	$ (42,961)	28,959
Purchased power agreements (b)						23,191
Current derivative instruments valuation						$ 52,150
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$	$ 10,886	$ 2,899	$ 13,785	$ (3,130)	$ 10,655
Natural gas commodity		71		71		71
Total noncurrent derivative liabilities	$	$ 10,957	$ 2,899	$ 13,856	$ (3,130)	10,726
Purchased power agreements (b)						283,131
Noncurrent derivative instruments valuation						$ 293,857

(a) Reported in other investments on the consolidated balance sheet, which also includes $101.6 million of equity investments in unconsolidated subsidiaries and $26.4 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. There were no transfers that occurred between levels during the three and six months ended June 30, 2010.

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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		Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	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
U.S. 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	$ 581,995	$ 573,637	$ 93,107	$ 1,248,739	$	$ 1,248,739

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	Dec. 31, 2009					
(Thousands of Dollars)	Level 1	Fair Value 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 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.

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. 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.

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

	Three Months Ended June 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 April 1	$ 3,946	$ 109,044	$ 44,125	$ 3,691	$ 90,257	$ 15,295
Purchases and settlements, net	273	(45,329)	(4,219)	(863)	(21,436)	(1,878)
Transfers out of Level 3				569		
Losses recognized in earnings	(1,406)			(2,347)		
Gains recognized as regulatory assets and liabilities	6,993	1,344	161	48,261	3,409	690
Balance at June 30	$ 9,806	$ 65,059	$ 40,067	$ 49,311	$ 72,230	$ 14,107

	Six Months Ended June 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	(1,159)	(19,698)	27,933	(1,223)	(30,034)	1,908
Transfers out of Level 3				569		
Losses recognized in earnings	(7,166)			(2,076)		
(Losses) gains recognized as regulatory assets and liabilities	(9,911)	3,568	216	28,820	3,803	1,237
Balance at June 30	$ 9,806	$ 65,059	$ 40,067	$ 49,311	$ 72,230	$ 14,107

Losses on Level 3 commodity derivatives recognized in earnings for the three and six months ended June 30, 2010, include $1.2 million and $1.8 million, respectively, of net unrealized losses relating to commodity derivatives held at June 30, 2010. Losses on Level 3 commodity derivatives recognized in earnings for the three and six months ended June 30, 2009, included $0.6 million and $4.4 million of net unrealized gains relating to commodity derivatives held at June 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.

11. Financial Instruments

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

	June 30, 2010	Dec. 31, 2009

(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Nuclear decommissioning fund	$ 1,248,613	$ 1,248,613	$ 1,248,739	$ 1,248,739
Other investments	9,084	9,084	9,649	9,649
Long-term debt, including current portion	8,955,452	10,038,748	8,432,442	9,026,257

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The fair value of cash and cash equivalents, notes and accounts receivable and notes and accounts payable are not materially different from their carrying amounts. 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 June 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)		**June 30, 2010**		**Dec. 31, 2009**
Guarantees issued and outstanding	$	72.7	$	76.4
Known exposure under these guarantees		17.9		18.0
Bonds with indemnity protection		30.7		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 June 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, Net

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

		Three Months Ended June 30,				**Six Months Ended June 30,**		
(Thousands of Dollars)		**2010**		**2009**		**2010**		**2009**
Interest income	$	1,243	$	3,140	$	3,294	$	6,066
Other nonoperating income		575		2,331		1,159		2,830
Insurance policy expense		(88)		(2,371)		(1,748)		(3,343)
Other nonoperating expense		(21)		(81)		(21)		(182)

Other income, net	$	1,709	$	3,019	$	2,684	$	5,371

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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.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2010					
Operating revenues from external customers	$ 2,040,702	$ 249,410	$ 17,652	$	$ 2,307,764
Intersegment revenues	259	2,857		(3,116)	
Total revenues	$ 2,040,961	$ 252,267	$ 17,652	$ (3,116)	$ 2,307,764
Income (loss) from continuing operations	$ 138,999	$ 10,243	$ (13,617)	$	$ 135,625
Three Months Ended June 30, 2009					
Operating revenues from external customers	$ 1,733,695	$ 265,884	$ 16,504	$	$ 2,016,083
Intersegment revenues	161	627		(788)	
Total revenues	$ 1,733,856	$ 266,511	$ 16,504	$ (788)	$ 2,016,083
Income (loss) from continuing operations	$ 116,199	$ 11,796	$ (10,931)	$	$ 117,064

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2010					
Operating revenues from external customers	$ 4,036,294	$ 1,039,560	$ 39,372	$	$ 5,115,226
Intersegment revenues	462	4,560		(5,022)	
Total revenues	$ 4,036,756	$ 1,044,120	$ 39,372	$ (5,022)	$ 5,115,226
Income (loss) from continuing operations	$ 254,181	$ 73,269	$ (24,485)	$	$ 302,965
Six Months Ended June 30, 2009					
Operating revenues from external customers	$ 3,620,252	$ 1,054,560	$ 36,813	$	$ 4,711,625
Intersegment revenues	418	1,921		(2,339)	
Total revenues	$ 3,620,670	$ 1,056,481	$ 36,813	$ (2,339)	$ 4,711,625
Income (loss) from continuing operations	$ 237,641	$ 72,070	$ (16,829)	$	$ 292,882

14. Common Stock and Equivalents

Xcel Energy has common stock equivalents consisting of 401(k) equity awards and stock options. Restricted stock units and performance shares are included as common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the period being reported.

For the three months ended June 30, 2010 and 2009, Xcel Energy had approximately 6.5 million and 7.6 million stock options outstanding, respectively, that were antidilutive and excluded from the earnings per share calculation. For the six months ended June 30, 2010 and 2009, Xcel Energy had approximately 6.6 million and 7.7 million stock options outstanding, respectively, that were antidilutive and excluded from the earnings per share calculation.

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

	Three Months Ended June 30, 2010			Three Months Ended June 30, 2009		
(Amounts in thousands, except per share data)	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**
Net income	$ 139,776			$ 117,107		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	138,716	460,041	$ 0.30	116,047	456,307	$ 0.25
Effect of dilutive securities:						
401(k) equity awards		391			459	
Diluted earnings per share:						
Earnings available to common shareholders	$ 138,716	460,432	$ 0.30	$ 116,047	456,766	$ 0.25

	Six Months Ended June 30, 2010			Six Months Ended June 30, 2009		
(Amounts in thousands, except per share data)	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**
Net income	$ 306,894			$ 291,174		
Less: Dividend requirements on preferred stock	(2,120)			(2,120)		
Basic earnings per share:						
Earnings available to common shareholders	304,774	459,483	$ 0.66	289,054	455,753	$ 0.63
Effect of dilutive securities:						
401(k) equity awards		585			609	
Diluted earnings per share:						
Earnings available to common shareholders	$ 304,774	460,068	$ 0.66	$ 289,054	456,362	$ 0.63

15. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended June 30,			
	2010	**2009**	**2010**	**2009**
(Thousands of Dollars)	**Pension Benefits**		**Postretirement Health Care Benefits**	
Service cost	$ 18,956	$ 16,744	$ 965	$ 1,057
Interest cost	41,853	43,046	10,861	13,050
Expected return on plan assets	(58,035)	(64,909)	(7,131)	(5,993)
Amortization of transition obligation			3,611	3,726
Amortization of prior service cost (credit)	5,164	6,154	(1,233)	(711)
Amortization of net loss	13,134	3,299	3,113	4,779
Net periodic pension cost	21,072	4,334	10,186	15,908
Costs not recognized and additional cost recognized due to the effects of regulation	(6,314)	(959)	973	973

Net benefit cost recognized for financial reporting	$	14,758	$	3,375	$	11,159	$	16,881

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	Six Months Ended June 30,			
	2010	2009	2010	2009
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 36,574	$ 32,730	$ 2,003	$ 2,333
Interest cost	82,505	84,895	21,390	25,206
Expected return on plan assets	(116,159)	(128,269)	(14,265)	(11,388)
Amortization of transition obligation			7,222	7,222
Amortization of prior service cost (credit)	10,328	12,309	(2,466)	(1,363)
Amortization of net loss	24,158	6,228	5,822	9,665
Net periodic pension cost	37,406	7,893	19,706	31,675
Costs not recognized and additional cost recognized due to the effects of regulation	(13,640)	(1,446)	1,946	1,946
Net benefit cost recognized for financial reporting	$ 23,766	$ 6,447	$ 21,652	$ 33,621

16. PSCo Agreement to Acquire Assets from Calpine Development Holdings, Inc.

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 acquisition is expected to close in December 2010.

The Rocky Mountain Energy Center is a 621 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 developed from the PSCo 2007 resource plan in which the assets were offered as part of the CPUC competitive bidding process. The offer was the least cost option for thermal resources to be acquired under the plan.

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, FERC issued an order approving the acquisition. The parties must obtain approval of the Federal Communications Commission for transfer of radio licenses associated with the plants, which is the remaining federal regulatory approval. The procedural schedule for state regulatory approval by the CPUC is as follows:

- Intervenor answer testimony due Aug. 9, 2010;
- Rebuttal and cross-answer testimony due Sept. 3, 2010;
- Hearings are Sept. 20 through Sept. 22, 2010;
- Deliberations due Oct. 18, 2010;

- Initial CPUC decision by Oct. 29, 2010; and
- Final decision expected on or before Dec. 1, 2010.

17. Subsequent Event Settlement with Provident Life & Accident Insurance Company

In July 2010, Xcel Energy, PSCo and PSRI (Xcel Energy) entered into a full and final settlement agreement with Provident related to all claims asserted by Xcel Energy against Provident in a lawsuit associated with Xcel Energy s discontinued COLI program. Under the terms of the settlement, Xcel Energy was paid $25 million by Provident and Reassure America Life Insurance Company. Xcel Energy will record this settlement of $25 million in the third quarter of 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, pote expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including 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 June 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 June 30,		Six Months Ended June 30,	
Diluted Earnings (Loss) Per Share	**2010**	**2009**	**2010**	**2009**
PSCo	$ 0.17	$ 0.13	$ 0.40	$ 0.31
NSP-Minnesota	0.09	0.11	0.24	0.27
SPS	0.05	0.03	0.07	0.06
NSP-Wisconsin	0.01	0.01	0.04	0.06
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.01
Regulated utility continuing operations	0.33	0.29	0.77	0.71
Holding company and other costs	(0.04)	(0.04)	(0.06)	(0.07)
Ongoing diluted earnings per share	**0.29**	**0.25**	**0.71**	**0.64**
Medicare Part D and PSRI			(0.06)	(0.01)
	0.29	**0.25**	**0.65**	**0.63**

Earnings per share from continuing operations								
Earnings per share from discontinued operations		0.01				0.01		
GAAP diluted earnings per share	$	**0.30**	$	**0.25**	$	**0.66**	$	**0.63**

Ongoing earnings for the second quarter of 2010 increased primarily due to higher electric margins as a result of the impact of constructive rate case outcomes in Colorado, the reversal of previously established fuel cost allocation reserves at SPS, favorable weather and increased electric sales. The higher electric margin was partially offset by expected increases in O&M.

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) 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.

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 dating back to tax year 1993, related to the PSRI COLI program.

PSCo Earnings at PSCo increased by four cents per share for the second quarter and by nine cents per share for the six months ended June 30, 2010. The increase is primarily due to new electric rates that went into effect in July 2009 and during 2010 and electric sales growth. The increase was partially offset by higher operating and maintenance expenses and depreciation.

NSP-Minnesota Earnings at NSP-Minnesota decreased by two cents per share for the second quarter and by three cents per share for the six months ended June 30, 2010. The decrease is largely due to higher O&M, partially offset by electric sales growth.

SPS Earnings at SPS increased by two cents per share for the second quarter and by one cent per share for the six months ended June 30, 2010. The increase is due to new electric rates that went into effect in February 2009 and July 2009, the resolution of certain fuel cost allocation issues in the second quarter (see further discussion in Note 6. Rate Matters), and electric sales growth which were partially offset by higher operating costs.

NSP-Wisconsin Earnings at NSP-Wisconsin were flat for the second quarter and decreased by two cents per share for the six months ended June 30, 2010. The year-to-date decrease is due to decreased fuel recovery and higher O&M, partially offset by new electric rates, which were effective in January 2010.

Discontinued Operations Earnings from discontinued operations increased by one cent per share for the second quarter and the six months ended June 30, 2010. The increase is largely due to the recognition of a tax benefit related to a previously held investment.

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

Diluted Earnings (Loss) Per Share	**Three Months Ended June 30,**	**Six Months Ended June 30,**
2009 GAAP diluted earnings per share	**$ 0.25**	**$ 0.63**
PSRI		0.01
2009 ongoing diluted earnings per share	**0.25**	**0.64**

Components of change 2010 vs. 2009				
Higher electric margins		0.16		0.22
Higher operating and maintenance expenses		(0.06)		(0.07)
Higher conservation and DSM expenses (generally offset in revenues)		(0.02)		(0.04)
Higher depreciation and amortization		(0.01)		(0.01)
Lower AFUDC equity		(0.01)		(0.02)
Higher taxes (other than income taxes)		(0.01)		(0.02)
Higher natural gas margins				0.02
Other, net		(0.01)		(0.01)
2010 ongoing diluted earnings per share		**0.29**		**0.71**
Medicare Part D and PSRI				(0.06)
2010 earnings per share from continuing operations		**0.29**		**0.65**
Earnings per share from discontinued operations		0.01		0.01
2010 GAAP diluted earnings per share	$	**0.30**	$	**0.66**

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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 June 30, 2010	2009	Six Months Ended June 30, 2010	2009
GAAP income (loss) by segment				
Regulated electric income	$ 139.0	$ 116.2	$ 254.2	$ 237.6
Regulated natural gas income	10.2	11.8	73.3	72.1
Other income (loss) (a)	3.9	6.6	(0.4)	13.7
Segment income continuing operations	153.1	134.6	327.1	323.4
Holding company and other costs (a)	(17.5)	(17.5)	(24.1)	(30.5)
Total income continuing operations	135.6	117.1	303.0	292.9
Income (loss) from discontinued operations	4.2		3.9	(1.7)
Total GAAP net income	$ 139.8	$ 117.1	$ 306.9	$ 291.2

Contributions to Earnings Per Share	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
GAAP earnings (loss) by segment				
Regulated electric	$ 0.30	$ 0.25	$ 0.55	$ 0.52
Regulated natural gas	0.02	0.03	0.16	0.16
Other (a)	0.01	0.01		0.02
Segment earnings per share continuing operations	0.33	0.29	0.71	0.70
Holding company and other costs(a)	(0.04)	(0.04)	(0.06)	(0.07)
Total earnings per share continuing operations	0.29	0.25	0.65	0.63
Discontinued operations	0.01		0.01	
Total GAAP earnings per share diluted	$ 0.30	$ 0.25	$ 0.66	$ 0.63

(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.

Weather Xcel Energy s earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase O&M. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce O&M. The 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.

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Estimated Impact of Temperature Changes on Regulated Earnings The following table summarizes the estimated impact on earnings per share of temperature variations compared with sales under normal weather conditions.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009	2010 vs. Normal	2009 vs. Normal	2010 vs. 2009
Retail electric	$ 0.01	$ (0.01)	$ 0.02	$ 0.01	$ (0.01)	$ 0.02
Firm natural gas	(0.01)	0.00	(0.01)	(0.01)	(0.01)	0.00
Total	**$** 0.00	**$** (0.01)	**$** 0.01	**$** 0.00	**$** (0.02)	**$** 0.02

While there were regional weather variations across our service territory, the earnings per share impact was diminished due to different electric per unit contributions to margins from sales among these territories.

Sales Growth (Decline) The following table summarizes Xcel Energy s regulated sales growth (decline) for actual and weather-normalized energy sales.

	Three Months Ended June 30,		Six Months Ended June 30,	
	Actual	Normalized	Actual	Normalized
Electric residential	4.1%	1.0%	4.1%	2.1%
Electric commercial and industrial	3.0	2.1	1.8	1.3
Total retail electric sales	3.2	1.8	2.4	1.5
Firm natural gas sales	(5.6)	(1.2)	3.2	0.7

Electric Revenues and Margin

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel and purchased energy cost-recovery mechanisms for customers in most states, the fluctuations in these costs do not materially affect electric margin. The following tables detail the electric revenues and margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of Dollars)	**2010**	**2009**	**2010**	**2009**
Electric revenues	$ 2,041	$ 1,734	$ 4,036	$ 3,620
Electric fuel and purchased power	(986)	(797)	(1,975)	(1,722)
Electric margin	$ 1,055	$ 937	$ 2,061	$ 1,898

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Fuel and purchased power cost recovery	$ 178	$ 245
Retail rate increases (Colorado, Wisconsin, South Dakota and New Mexico)	70	124
Conservation and DSM revenue and incentive (partially offset by expenses)	14	28
SPS fuel cost allocation regulatory accruals	11	11
Estimated impact of weather	10	11
Retail sales increase (excluding weather impact)	8	14
Sales mix and demand revenue	7	9
NSP-Minnesota 2009 rate case adjustment for final rates (largely offset in depreciation expense)	(10)	(19)
Firm wholesale	(3)	(10)
Other, net	22	3
Total increase in electric revenues	$ 307	$ 416

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Electric Margin

(Millions of Dollars)	Three Months Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Retail rate increases (Colorado, Wisconsin, South Dakota and New Mexico)	$ 70	$ 124
Conservation and DSM revenue and incentive (partially offset by expenses)	14	28
SPS fuel cost allocation regulatory accruals	11	11
Estimated impact of weather	10	11
Retail sales increase (excluding weather impact)	8	14
Sales mix and demand revenue	7	9
NSP-Minnesota 2009 rate case adjustment for final rates (largely offset in depreciation expense)	(10)	(19)
NSP-Wisconsin fuel recovery	(3)	(7)
Other, net	11	(8)
Total increase in electric margin	$ 118	$ 163

Natural Gas Revenues and Margin

The cost of natural gas tends to vary with changing sales requirements and the cost of wholesale natural gas purchases. However, due to purchased natural gas cost-recovery mechanisms for sales to retail customers, fluctuations in the wholesale cost of natural gas have little effect on natural gas margin. The following tables detail natural gas revenues and margin:

(Millions of Dollars)	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Natural gas revenues	$ 249	$ 266	$ 1,040	$ 1,055
Cost of natural gas sold and transported	(127)	(146)	(708)	(738)
Natural gas margin	$ 122	$ 120	$ 332	$ 317

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Purchased natural gas adjustment clause recovery	$ (20)	$ (26)
Estimated impact of weather	(2)	1
Rate increase (Minnesota interim)		3
Conservation and DSM revenue and incentive (partially offset by expenses)	4	5
Other, net	1	2

Total decrease in natural gas revenues	$ (17)	$ (15)

Natural Gas Margin

(Millions of Dollars)	**Three Months Ended June 30, 2010 vs. 2009**	**Six Months Ended June 30, 2010 vs. 2009**
Conservation and DSM revenue and incentive (partially offset by expenses)	$ 4	$ 5
Estimated impact of weather	(2)	1
Rate increase (Minnesota interim)		3
Other, net		6
Total increase in natural gas margin	$ 2	$ 15

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Non-Fuel Operating Expense and Other Items

O&M Expenses Other O&M expenses increased by approximately $44.2 million, or 9.4 percent, for the second quarter and by $53.3 million, or 5.6 percent for the six months ended June 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 June 30, 2010 vs. 2009	Six Months Ended June 30, 2010 vs. 2009
Higher employee benefit costs	$ 13	$ 5
Higher labor costs	7	11
Higher nuclear plant operation costs	7	5
Higher plant generation costs	6	17
Nuclear outage costs, net of deferral	5	9
Other, net	6	6
Total increase in other operating and maintenance expenses	$ 44	$ 53

- Higher employee benefit costs are primarily related to performance based incentive compensation as well as pension costs.
- Higher labor costs are primarily due to annual wage increases that were effective in March 2010 and July 2009.
- Higher plant generation costs are primarily attributable to a higher level of scheduled maintenance and overhaul work.
- Higher nuclear outage costs are due to the timing and cost of nuclear refueling outages.

Conservation and DSM Program Expenses Conservation and DSM program expenses increased by approximately $14.1 million, or 34.1 percent, for the second quarter and by $27.0 million, or 31.1 percent for the six months ended June 30, 2010, compared with the same periods in 2009. The higher expense is attributable to the expansion of programs and regulatory commitments. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization Depreciation and amortization expenses increased by approximately $9.2 million, or 4.5 percent, for the second quarter and by $6.6 million, or 1.6 percent for the six months ended June 30, 2010, compared with the same periods in 2009. The higher depreciation expense is primarily due to normal system expansion.

Taxes (Other Than Income Taxes) Taxes (other than income taxes) increased by approximately $7.9 million, or 10.9 percent, for the second quarter and by $12.3 million, or 8.2 percent for the six months ended June 30, 2010, compared with the same periods in 2009. The increase is primarily due to an increase in property taxes in Colorado and Minnesota.

Equity Earnings of Unconsolidated Subsidiaries Equity earnings of unconsolidated subsidiaries increased by approximately $4.1 million, for the second quarter and by $8.4 million for the six months ended June 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 $9.0 million for the second quarter and by $16.4 million for the six months ended June 30, 2010, compared with the same periods in 2009. The decrease was partially due to recovery of Comanche Unit 3 financing costs through base rates and lower AFUDC rates.

Interest Charges Interest charges increased by approximately $2.2 million, or 1.5 percent, for the second quarter and by $4.2 million, or 1.5 percent for the six months ended June 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 $19.0 million for the second quarter of 2010, compared with 2009. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 36.2 percent for the second quarter of 2010, compared with 33.1 percent for the same period in 2009.

Income tax expense for continuing operations increased by $53.8 million for the first six months of 2010, compared with the first six months of 2009. The increase in income tax expense was primarily due to an increase in pretax income, 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 39.6 percent for the first six months of 2010, compared with 33.1 percent for the same period in 2009.

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The higher effective tax rate was primarily due to a higher forecasted annual effective tax rate for 2010 as compared to 2009 as well as the following:

(Millions of Dollars)	Three Months Ended June 30, 2010 Dollars	Three Months Ended June 30, 2010 Effective Tax Rate	Six Months Ended June 30, 2010 Dollars	Six Months Ended June 30, 2010 Effective Tax Rate
Income tax expense	$ 76.9	36.2%	$ 198.8	39.6%
Medicare Part D (a)			(17.0)	(3.4)
PSRI (a)			(7.7)	(1.5)
Reversal of valuation allowance for certain state tax credit carryovers			5.3	1.1
Income tax expense (excluding items above)	$ 76.9	36.2%	$ 179.4	35.8%

(a) See Note 5. Income Taxes

The higher forecasted annual effective tax rate for the second quarter and the first six months of 2010 as compared to 2009, which is used in the determination of quarterly income tax expense, was primarily due to reduced plant-related deductions and increased state unitary tax expense in 2010, and the elimination of tax benefits for Medicare Part D subsidies as well as research credits 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.

Public Utility Regulation

NSP-Minnesota

Aggregators of Retail Customers (ARCs) In 2009, the FERC adopted rules requiring MISO and other regional transmission organizations (RTOs) to allow ARCs to offer demand response aggregation services to end-use customers in the states served by NSP-Minnesota, unless the relevant state regulatory agency prohibited the operation of ARCS. Under MISO proposed tariff revisions, ARCs would operate in competition with the state-regulated retail demand response programs offered by NSP-Minnesota. MISO requested its tariff revisions be effective in June 2010, however FERC has not issued an order on MISO s ARC-related tariff revisions. In 2010, the MPUC opened an investigation regarding possible operation of ARCs in Minnesota. In its response to an MPUC notice seeking comments, NSP-Minnesota requested the MPUC to prohibit ARCs. NSP-Minnesota also filed requests with the North Dakota Public Service Commission (NDPSC) and South Dakota Public Utilities Commission (SDPUC) in March 2010 asking the regulatory agencies to prohibit operations of ARCs in their respective states. In May 2010, the MPUC and SDPUC issued orders prohibiting, or temporarily prohibiting, the operation of ARCs. In May 2010, the NDPSC issued a notice of opportunity for a hearing; no parties provided comments. A NDPSC decision is expected in the third quarter of 2010.

Excelsior Energy In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration that NSP-Minnesota be compelled to enter into an agreement to purchase the output from two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota as part of the Mesaba Energy Project. The MPUC referred this matter to a contested case hearing before an ALJ to act on Excelsior s petition. The contested case proceeding considered a 600 MW unit in Phase 1 and a second 600 MW unit in Phase 2 of the Mesaba Energy Project.

In its August 2007 Phase 1 order, the MPUC disapproved the terms and conditions of Excelsior s proposed power purchase agreement, and found that Excelsior and NSP-Minnesota should resume negotiations toward an acceptable purchase power agreement, with assistance from the OES and the guidance provided by the order.

In May 2009, the MPUC affirmed its previous order to deny Excelsior Energy s Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW IGCC generating facility, which closed the docket. In August 2009, Excelsior appealed the MPUC decision to the Minnesota Court of Appeals. On May 18, 2010, the Minnesota Court of Appeals affirmed the decision of the MPUC. Excelsior did not file a petition for review by the Minnesota Supreme Court, making the Court of Appeals decision final.

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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 will file its next resource plan in August of 2010.

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-Hampton project is expected to be delayed to 2015, more than one year after the date provided in the MPUC CON decision. The MPUC set the notice of change for comments and a decision is expected during the third quarter of 2010.

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 to St. Cloud project and five of the six segments of the Brookings-Hampton project. One segment of the Brookings-Hampton 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. and Grand Rapids, Minn. Route permit hearings were concluded in May 2010, and an MPUC decision is anticipated in the third quarter of 2010. The Bemidji-Grand Rapids 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 Power Operations and Waste Disposal NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant, which has two units. See additional discussion regarding the nuclear generating plants at Note 18 to the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2009.

High-Level Radioactive Waste Disposal The federal government has the responsibility to permanently dispose of domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the DOE to implement a program for nuclear high-level waste management. This includes the siting, licensing, construction and operation of a repository for spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent federal storage or disposal facility. In 2002, the U. S. Congress designated Yucca Mountain, Nevada as the first deep geologic repository over the objections of the Governor of Nevada. In 2008, the DOE submitted an application to construct a deep geologic repository at Yucca Mountain to the Nuclear Regulatory Commission (NRC).

In 2010, the DOE announced its intention to stop the Yucca Mountain project and requested the NRC to approve the withdrawal of the application. In parallel with the action to stop the Yucca Mountain project, the Secretary of Energy convened a Blue Ribbon Commission to recommend alternatives to Yucca Mountain for disposing of used nuclear fuel. The final report containing recommendations from the Blue Ribbon Commission is expected in early 2012. A number of parties have challenged the DOE s authority to stop the Yucca Mountain project and to withdraw the application from the NRC. The utility industry, including Xcel Energy, is represented in the challenges by the Nuclear Energy Institute (NEI). In light of the DOE s plan to stop the Yucca Mountain project and to withdraw its application from the NRC, Xcel Energy in a separate action has requested the Secretary of Energy to set the fee collection rate for the Nuclear Waste Fund to zero until a definitive program is in place. In April 2010, the NEI, on behalf of its members, including Xcel Energy, filed a lawsuit against the DOE in federal court, requesting that the fee be suspended.

On June 30, 2010, the Atomic Safety and Licensing Board (ASLB) issued a ruling that the DOE could not withdraw the Yucca Mountain application. The NRC has set appeal and comment dates to the three-judge NRC panel s decision. A decision from the NRC Commissioners could come in the third quarter 2010.

To date, the DOE has not accepted any of NSP-Minnesota s spent nuclear fuel. NSP-Minnesota has interim on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear generating plants. As of June 30, 2010, there were 26 casks loaded and stored at the Prairie Island plant and 10 casks loaded and stored at the Monticello plant. See Note 7 to the consolidated financial statements for a discussion of the legal proceedings against the DOE related to the nuclear waste disposal matter.

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Nuclear Plant Power Uprates and Life Extension

Prairie Island Life Extension In April 2008, NSP-Minnesota filed an application with the 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 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. If the admitted contention is not resolved, the resulting adjudicatory process is expected to add approximately eight months onto the NRC s standard 22 month review schedule, resulting in an anticipated decision on the Prairie Island license renewal in late 2010.

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 in suspension by the ASLB, to allow NRC staff to address concerns related to two different uprate petitions, including Monticello 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.

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 project will convert a third boiler to biomass gasification technology allowing the plant to use up to 100 percent biomass in all three boilers. 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. The project is expected to improve the environmental performance of the plant and contribute towards state RES in the region.

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, which is a FERC-approved tariff that allows NSP-Minnesota and NSP-Wisconsin to share all NSP System costs for the electric production and transmission systems of NSP-Minnesota and NSP-Wisconsin, which are managed as an integrated system and are jointly referred to as the NSP System.

In the second quarter of 2010, NSP-Wisconsin completed more detailed analyses of the project to determine a preferred gasification technology, refine the construction schedule and more precisely estimate the project cost. 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 requested a three-to-six month time period to review other options that may be viable for the third boiler at Bay Front. The PSCW granted NSP-Wisconsin s request. 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. Under the revised statutes, 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 symmetrical annual tolerance band established by the PSCW. 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. The legislation requires the PSCW to promulgate rules to implement the new statutes. The PSCW has indicated its intention to complete the rulemaking in time to allow the new rules to go into effect for calendar year 2011.

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PSCo

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 negotiation of purchased power contracts from a pool of PV solar bidders, rather than designating specific bidders. The CPUC approved the selection of about 900 MW of traditional gas-fired resources. The CPUC preferred that PSCo file its next resource plan in the normal course of business in the fall of 2011 rather than making an interim filing in 2010. The Colorado 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. The parties must obtain approval of the Federal Communications Commission for transfer of radio licenses associated with the plants, which is the remaining federal regulatory approval. The application includes prompt recovery of revenue requirements associated with the transaction. The matter has been referred to an ALJ and the ALJ has set a schedule to resolve the matter by the target closing date of Dec. 1, 2010. Intervenor testimony is due Aug. 9, 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 is pending before the CPUC.

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 need and public convenience 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. As noted in the aforementioned PSCo Resource Plan, 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. Hearings before an ALJ were conducted in February 2010, and additional hearings were held on July 26 and 30, 2010.

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. The CPUC commenced a rulemaking in April 2010 to incorporate changes from the 2010 RES into CPUC rules. PSCo believes that its forecasted plan acquisitions of renewable resources only need minor modification to comply with the new standard.

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In June 2010, Colorado enacted Solar Garden legislation that allows PSCo customers to purchase shares of a larger solar facility instead of putting solar panels on their rooftops. In June 2010, the CPUC indicated that it would initiate a separate rulemaking to accommodate this new law. The rulemaking is expected to commence prior to October 2010. In PSCo s 2011 RES compliance plan, PSCo is expected to include its initial Solar Garden product offering.

Colorado Clean Air-Clean Jobs Act The Colorado Clean Air-Clean Jobs Act (the Act) was signed into law in April 2010. The Act requires 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 requires PSCo to prepare comparative evaluations of different scenarios, including a scenario where emission controls are installed on the coal plants and a scenario where coal plants are repowered or replaced by natural gas by Jan. 1, 2015. 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 Act, PSCo is entitled to fully 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 any earnings deficiency, additional relief, including a more comprehensive rider to recover other plant costs such as depreciation and O&M expense, or a multi-year rate plan are allowed. The Act permits the CPUC to consider interim rate increases after Jan. 1, 2012 while the rate filing is pending.

In June, CPUC ordered PSCo to file certain information so that it could process the August filing in a timely manner. PSCo has filed a significant amount of information with the CPUC and in July 2010 provided a list of the different scenarios it has proposed to model for its plan filing. Also in July 2010, the CPUC rejected a motion by Colorado Independent Energy Association, representing certain independent power producers that would require PSCo to consider purchasing replacement capacity under the plan from these entities. See additional information set forth in Note 7 to the consolidated financial statements in this Quarterly Report on Form 10-Q.

SmartGridCity Certificate of Public Convenience and Necessity (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 filed that application on March 10, 2010 along with direct testimony. Answer testimony was received from Parties on July 19, 2010. The CPUC staff, the OCC, and the Governor s Energy Office (GEO) support the issuance of the CPCN and cost recovery of the amounts included in the rate case. Two parties, Leslie Glustrom and Arapahope Community Team (ACT) oppose issuance of the CPCN. PSCo is currently recovering the revenue requirements on $42 million of capital costs and $4 million in annual O&M costs. The OCC and Glustrom recommended partial recovery of capital costs while ACT recommended no recovery. PSCo s rebuttal testimony is due in early August 2010. Separately, PSCo has received approval to conduct both a pricing and an in-home device pilot program to evaluate the customer response to price signals enabled by the smart technology.

SPS

Jones Certificate of Convenience and Necessity (CCN) SPS applied for a CCN in Texas with the PUCT. The parties reached a settlement recommending approval. The PUCT is expected to act in the third quarter of 2010. A similar CCN approval application was made with the NMPRC. The matter has been referred to an ALJ and settlement revisions are anticipated.

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 with the New Mexico Supreme Court and the New Mexico Industrial Energy Consumers. In July 2010, SPS filed its application regarding permanent solutions to removing disincentives and requested direct lost margin recovery.

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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.

MISO Generation Interconnection 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 of costs associated with 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 are due at FERC by Sept. 10, 2010, and 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 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) 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. The first settlement conference is scheduled for August 2010. 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.

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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.

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 and is awaiting issuance of the final spot check audit report. The matter will then proceed to the regional entity enforcement process. The extent the regional entities or NERC may seek to impose penalties for violations of CIP standards is unknown at this time.

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 June 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 is currently evaluating 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 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 June 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:

	Six Months Ended June 30,	
(Thousands of Dollars)	**2010**	**2009**
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 9,628	$ 4,169
Contracts realized or settled during the period	(1,980)	(13,144)
Commodity trading contract additions and changes during period	7,750	14,372
Fair value of commodity trading net contract assets outstanding at June 30	$ 15,398	$ 5,397

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At June 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	$ 3,651	$ 8,570	$	$	$ 12,221
	2		1,311	592	284	2,187
PSCo	1	(205)	942			737
	2	178	457			635
		$ 3,624	$ 11,280	$ 592	$ 284	$ 15,780

		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	$ (382)	$	$	$	$ (382)
		$ (382)	$	$	$	$ (382)

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 June 30, 2010, a 10 percent increase in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.8 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.4 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 June 30,	VaR Limit	Average	High	Low
2010	$ 0.35	$ 5.00	$ 0.26	$ 0.51	$ 0.10
2009	0.63	5.00	0.50	1.73	0.14

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 June 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 $2.1 million annually, or approximately $0.5 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 June 30, 2010, these funds were invested in a diversified portfolio of fixed income and equity securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk 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 June 30, 2010, a 10 percent increase in prices would have resulted in a net decrease in credit exposure of $6.6 million, while a decrease of 10 percent would have resulted in an increase in credit exposure of $10.8 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 June 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 June 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 approximately 1 percent and 17 percent of total assets and liabilities measured at fair value, respectively, at June 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 $8.7 million and $3.7 million of estimated fair values, respectively, for FTRs held at June 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. Level 3 commodity derivatives assets and liabilities include $7.9 million and $3.0 million of estimated fair values, respectively, for commodity forwards and options held at June 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 $105.1 million in the nuclear decommissioning fund at June 30, 2010 (approximately 8 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

	Six Months Ended June 30,	
(Millions of Dollars)	**2010**	**2009**
Cash provided by operating activities	$ 912	$ 1,126

Cash provided by operating activities decreased by $214 million for the first six months of 2010, compared with the first six months of 2009. The decrease was primarily due to changes in working capital due to lower cash flows from inventories, accounts receivable and accrued unbilled revenues as a result of reduced cost of natural gas.

	Six Months Ended June 30,	
(Millions of Dollars)	**2010**	**2009**
Cash used in investing activities	$ (934)	$ (934)

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

	Six Months Ended June 30,	
(Millions of Dollars)	**2010**	**2009**
Cash used in financing activities	$ (20)	$ (61)

Cash used in financing activities decreased by $41 million for the first six months of 2010, compared with the first six months of 2009. The decrease 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 and SEC with expanded regulatory authority over energy 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 result in extensive margin and fee requirements. Additionally there may be material increased reporting requirements. Based on our preliminary analysis the bill contains provisions that should exempt certain derivatives end-users such as Xcel Energy from much of the clearing and margining requirements. However, if Xcel Energy does not qualify for the exemption, 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 is currently evaluating 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 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 Clean Air-Clean Jobs legislation 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. Currently, credit support and other contract language are being negotiated and the deal is contingent on CPUC approval of the transaction terms and conditions which must occur prior to Dec. 15, 2010; otherwise the contract will be null and void.

Capital Sources

Settlement with Provident In July 2010, Xcel Energy, PSCo and PSRI (Xcel Energy) entered into a full and final settlement agreement with Provident related to all claims asserted by Xcel Energy against Provident in a lawsuit associated with Xcel Energy s discontinued COLI program. Under the terms of the settlement, Xcel Energy was paid $25 million by Provident and Reassure America Life Insurance Company. Xcel Energy will record this settlement of $25 million, or approximately $0.05 of nonrecurring earnings per share, in the third quarter of 2010. Xcel Energy does not consider this settlement to be part of ongoing earnings, as it is not expected to recur in the future.

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 June 30, 2010, approximately $4.2 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 July 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	$ 121.3	$ 360.9	$ 0.2	$ 361.1	December 2011
PSCo	675.1	4.5	670.6	2.7	673.3	December 2011
SPS	247.9	13.0	234.9	0.1	235.0	December 2011
Xcel Energy Holding Company	771.6	72.1	699.5	1.3	700.8	December 2011
NSP-Wisconsin(b)				14.1	14.1	
Total	$ 2,176.8	$ 210.9	$ 1,965.9	$ 18.4	$ 1,984.3	

(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.

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.

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.

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Registration Statements Xcel Energy s articles of incorporation authorize the issuance of one billion shares of common stock. As of June 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 June 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.
- NSP-Minnesota has $700 million of debt securities available under its currently effective registration statement.
- PSCo has $400 million of debt securities available under its currently effective registration statement. In March 2010, PSCo received authorization from the CPUC to issue up to $1.8 billion of long-term debt securities. The authorization expires in December 2013.
- 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 unsecured debt with a 10-year maturity and a coupon of 4.7 percent.
- NSP-Minnesota plans to issue approximately $500 million of first mortgage bonds in the third quarter of 2010.
- PSCo plans to issue approximately $400 million of first mortgage bonds in the fourth quarter of 2010.
- Xcel Energy plans to issue approximately $400 million of equity in 2010 or 2011.
- 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.

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. 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 grow approximately 1 percent.
- Weather-adjusted retail firm natural gas sales increase approximately 0 percent to 1 percent.
- Reflects 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 the Minnesota natural gas rate case and PSCo wholesale electric rate case.
- Increased rider revenue recovery of approximately $30 million.
- O&M expenses are projected to increase $115 million to $135 million, or 6 percent to 7 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 $15 million to $20 million.
- The effective tax rate is approximately 35 percent to 37 percent.
- Average common stock and equivalents total approximately 460 million shares.

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Item 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management s Discussion and Analysis under Item 2.

Item 4 CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in 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 June 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.

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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.

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.

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Item 6 EXHIBITS

* Indicates incorporation by reference

Certain portions of this agreement have been omitted pursuant to a request for confidential treatment and have been filed separately with the SEC.

2.01	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers, and PSCo, as Purchaser, dated as of April 2, 2010 (excluding certain schedules and exhibits referred to in the agreement, as amended, which the Registrant agrees to furnish supplementally to the SEC upon request).
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 No. 5 dated as of May 1, 2010 between Xcel Energy and Wells Fargo Bank, NA, as Trustee, creating $550,000,000 principal amount of 4.70 percent Senior Notes, Series due May 15, 2020 (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated May 13, 2010).
10.01*	Xcel Energy Executive Annual Incentive Award Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix A to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
10.02*	Xcel Energy 2005 Long-Term Incentive Plan (as amended and restated effective Feb. 17, 2010) (incorporated by reference to Appendix B to Schedule 14A, Definitive Proxy Statement to Xcel Energy Inc. (file no. 001-03034) dated April 6, 2010).
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.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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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)

July 30, 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)