XCEL ENERGY INC
Form 10-Q
October 30, 2009
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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 Sept. 30, 2009

or

o TRANSITION REPORTS 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 requirement 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 Oct. 26, 2009**
Common Stock, $2.50 par value	456,645,598 shares

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

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PART I FINANCIAL INFORMATION

Item 1 FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(amounts in thousands, except per share data)

	Three Months Ended Sept. 30, 2009	Three Months Ended Sept. 30, 2008	Nine Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2008
Operating revenues				
Electric	$ 2,128,955	$ 2,576,467	$ 5,749,207	$ 6,704,164
Natural gas	169,601	258,961	1,224,161	1,736,701
Other	16,006	16,252	52,819	54,718
Total operating revenues	2,314,562	2,851,680	7,026,187	8,495,583
Operating expenses				
Electric fuel and purchased power	982,103	1,513,935	2,703,952	3,871,437
Cost of natural gas sold and transported	71,638	155,804	809,791	1,298,731
Cost of sales other	4,915	4,528	14,268	14,095
Other operating and maintenance expenses	466,465	422,560	1,410,760	1,340,362
Conservation and demand side management program expenses	47,157	27,483	133,793	92,278
Depreciation and amortization	198,222	209,131	609,285	622,512
Taxes (other than income taxes)	78,914	70,245	229,025	218,220
Total operating expenses	1,849,414	2,403,686	5,910,874	7,457,635
Operating income	465,148	447,994	1,115,313	1,037,948
Other income (expense), net	(977)	9,736	4,394	27,270
Allowance for funds used during construction equity	18,618	16,319	55,565	45,478
Interest charges and financing costs				
Interest charges includes other financing costs of $5,103, $5,162, $15,255 and $15,294, respectively	139,347	139,777	420,447	405,671
Allowance for funds used during construction debt	(9,598)	(9,625)	(29,671)	(28,748)
Total interest charges and financing costs	129,749	130,152	390,776	376,923
Income from continuing operations before income taxes and equity earnings	353,040	343,897	784,496	733,773
Income taxes	135,610	121,551	280,581	252,765
Equity earnings of unconsolidated subsidiaries	4,363	349	10,760	1,154
Income from continuing operations	221,793	222,695	514,675	482,162
	(965)	94	(2,673)	(684)

Income (loss) from discontinued operations, net of tax								
Net income		220,828		222,789		512,002		481,478
Dividend requirements on preferred stock		1,060		1,060		3,180		3,180
Earnings available to common shareholders	$	219,768	$	221,729	$	508,822	$	478,298
Weighted average common shares outstanding:								
Basic		456,769		434,131		456,095		431,511
Diluted		457,453		439,397		456,729		436,716
Earnings per average common share:								
Basic	$	0.48	$	0.51	$	1.12	$	1.11
Diluted		0.48		0.51		1.11		1.10
Cash dividends declared per common share		0.25		0.24		0.73		0.71

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(amounts in thousands of dollars)

	Nine Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2008
Operating activities		
Net income	$ 512,002	$ 481,478
Remove loss from discontinued operations	2,673	684
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	644,224	676,691
Nuclear fuel amortization	59,520	46,765
Deferred income taxes	304,707	199,155
Amortization of investment tax credits	(5,213)	(5,824)
Allowance for equity funds used during construction	(55,565)	(45,478)
Equity earnings of unconsolidated subsidiaries	(10,760)	(1,154)
Dividends from equity method investees	20,999	
Share-based compensation expense	13,252	17,961
Net realized and unrealized hedging and derivative transactions	46,298	(34,049)
Changes in operating assets and liabilities:		
Accounts receivable	265,655	128,186
Accrued unbilled revenues	272,574	237,358
Inventories	111,780	(195,722)
Recoverable purchased natural gas and electric energy costs	(30,792)	(25,752)
Other current assets	(72,817)	21,794
Accounts payable	(286,019)	(198,877)
Net regulatory assets and liabilities	20,422	(47,765)
Other current liabilities	7,347	11,521
Change in other noncurrent assets	(2,014)	407
Change in other noncurrent liabilities	(172,291)	(44,423)
Operating cash flows used in discontinued operations	(17,166)	(11,494)
Net cash provided by operating activities	1,628,816	1,211,462
Investing activities		
Utility capital/construction expenditures	(1,310,686)	(1,523,365)
Allowance for equity funds used during construction	55,565	45,478
Purchase of investments in external decommissioning fund	(1,278,554)	(643,497)
Proceeds from the sale of investments in external decommissioning fund	1,276,417	610,953
Investment in WYCO Development LLC	(38,936)	(73,038)
Change in restricted cash	(1,389)	24,132
Other investments	3,472	(25,678)
Net cash used in investing activities	(1,294,111)	(1,585,015)
Financing activities		
Proceeds (repayment) of short-term borrowings, net	38,750	(824,560)
Proceeds from issuance of long-term debt	394,762	1,682,393
Repayment of long-term debt, including reacquisition premiums	(620,074)	(200,041)
Proceeds from issuance of common stock	4,174	351,357
Dividends paid	(309,320)	(303,157)
Net cash (used in) provided by financing activities	(491,708)	705,992
Net increase (decrease) in cash and cash equivalents	(157,003)	332,439
Net increase (decrease) in cash and cash equivalents discontinued operations	(1,989)	416
Cash and cash equivalents at beginning of period	249,198	51,120
Cash and cash equivalents at end of period	$ 90,206	$ 383,975
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (400,511)	$ (363,439)
Cash received (paid) for income taxes, net	21,857	(49,943)
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 33,116	$ 27,845
Supplemental disclosure of non-cash financing transactions:		
Issuance of common stock for reinvested dividends and 401(k) plans	$ 44,668	$ 48,872

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(amounts in thousands of dollars)

	Sept. 30, 2009	Dec. 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 90,206	$ 249,198
Accounts receivable, net	635,563	900,781
Accrued unbilled revenues	470,905	743,479
Inventories	554,929	666,709
Recoverable purchased natural gas and electric energy costs	63,635	32,843
Derivative instruments valuation	136,491	101,972
Prepayments and other	311,028	263,906
Current assets held for sale and related to discontinued operations	128,040	56,641
Total current assets	2,390,797	3,015,529
Property, plant and equipment, net	18,514,792	17,688,720
Other assets		
Nuclear decommissioning fund and other investments	1,365,601	1,232,081
Regulatory assets	2,216,473	2,357,279
Derivative instruments valuation	308,768	325,688
Other	154,486	157,742
Noncurrent assets held for sale and related to discontinued operations	130,291	181,456
Total other assets	4,175,619	4,254,246
Total assets	$ 25,081,208	$ 24,958,495
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 184,534	$ 558,772
Short-term debt	494,000	455,250
Accounts payable	811,624	1,120,324
Taxes accrued	223,278	220,542
Accrued interest	146,107	168,632
Dividends payable	112,840	108,838
Derivative instruments valuation	59,277	75,539
Other	326,780	331,419
Current liabilities held for sale and related to discontinued operations	28,058	6,929
Total current liabilities	2,386,498	3,046,245
Deferred credits and other liabilities		
Deferred income taxes	3,177,595	2,792,560
Deferred investment tax credits	100,503	105,716
Regulatory liabilities	1,265,541	1,194,596
Asset retirement obligations	1,186,690	1,135,182
Derivative instruments valuation	327,691	340,802
Customer advances	304,752	323,445
Pension and employee benefit obligations	902,214	1,030,532
Other	184,885	168,352
Noncurrent liabilities held for sale and related to discontinued operations	3,279	20,656
Total deferred credits and other liabilities	7,453,150	7,111,841
Commitments and contingent liabilities		
Capitalization		
Long-term debt	7,945,400	7,731,688
Preferred stockholders equity authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800	104,980	104,980
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: Sept. 30, 2009 456,251,313; Dec. 31, 2008 453,791,770	7,191,180	6,963,741
Total liabilities and equity	$ 25,081,208	$ 24,958,495

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (UNAUDITED)

(amounts in thousands)

	Common Stock Issued										
	Shares		Par Value		Additional Paid In Capital		Retained Earnings		Accumulated Other Comprehensive Income (Loss)		Total Common Stockholders Equity
Three Months Ended Sept. 30, 2009 and 2008											
Balance at June 30, 2008	430,917	$	1,077,292	$	4,306,239	$	1,017,488	$	(26,549)	$	6,374,470
Net income							222,789				222,789
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $195									273		273
Net derivative instrument fair value changes during the period, net of tax of $(1,741)									(2,522)		(2,522)
Unrealized loss - marketable securities, net of tax of $(87)									(123)		(123)
Comprehensive income for the period											220,417
Dividends declared:											
Cumulative preferred stock							(1,060)				(1,060)
Common stock							(106,545)				(106,545)
Issuances of common stock	17,699		44,247		311,340						355,587
Share-based compensation					5,471						5,471
Balance at Sept. 30, 2008	448,616	$	1,121,539	$	4,623,050	$	1,132,672	$	(28,921)	$	6,848,340
Balance at June 30, 2009	455,717	$	1,139,292	$	4,727,380	$	1,256,405	$	(49,354)	$	7,073,723
Net income							220,828				220,828
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $260									365		365
Net derivative instrument fair value changes during the period, net of tax of $(3,876)									(5,557)		(5,557)
Unrealized gain - marketable securities, net of tax of $62									90		90
Comprehensive income for the period											215,726
Dividends declared:											
Cumulative preferred stock							(1,060)				(1,060)
Common stock							(112,255)				(112,255)
Issuances of common stock	534		1,337		7,485						8,822
Share-based compensation					6,224						6,224
Balance at Sept. 30, 2009	456,251	$	1,140,629	$	4,741,089	$	1,363,918	$	(54,456)	$	7,191,180

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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		Accumulated	Total
	Shares	Par Value	Paid In Capital	Retained Earnings	Other Comprehensive Income (Loss)	Common Stockholders' Equity
Nine Months Ended Sept. 30, 2009 and 2008						
Balance at Dec. 31, 2007	428,783	$ 1,071,957	$ 4,286,917	$ 963,916	$ (21,788)	$ 6,301,002
Adoption of new accounting guidance for endorsement split-dollar life insurance, net of tax of $(1,038)				(1,640)		(1,640)
Net income				481,478		481,478
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $1,071					330	330
Net derivative instrument fair value changes during the period, net of tax of $(2,808)					(7,240)	(7,240)
Unrealized loss - marketable securities, net of tax of $(154)					(223)	(223)
Comprehensive income for the period						474,345
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(307,902)		(307,902)
Issuances of common stock	19,833	49,582	318,881			368,463
Share-based compensation			17,252			17,252
Balance at Sept. 30, 2008	448,616	$ 1,121,539	$ 4,623,050	$ 1,132,672	$ (28,921)	$ 6,848,340
Balance at Dec. 31, 2008	453,792	$ 1,134,480	$ 4,695,019	$ 1,187,911	$ (53,669)	$ 6,963,741
Net income				512,002		512,002
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $769					1,106	1,106
Net derivative instrument fair value changes during the period, net of tax of $(1,736)					(2,226)	(2,226)
Unrealized gain - marketable securities, net of tax of $230					333	333
Comprehensive income for the period						511,215
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(332,815)		(332,815)
Issuances of common stock	2,459	6,149	25,550			31,699
Share-based compensation			20,520			20,520
Balance at Sept. 30, 2009	456,251	$ 1,140,629	$ 4,741,089	$ 1,363,918	$ (54,456)	$ 7,191,180

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XCEL ENERGY INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of Sept. 30, 2009 and Dec. 31, 2008; the results of its operations and changes in stockholders equity for the three and nine months ended Sept. 30, 2009 and 2008; and its cash flows for the nine months ended Sept. 30, 2009 and 2008. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2009 up to Oct. 30, 2009, which is the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2008 balance sheet information has been derived from the audited 2008 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, 2008, filed with the SEC on Feb. 27, 2009. 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, 2008, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Reclassifications Equity earnings of Xcel Energy s unconsolidated subsidiaries were reclassified from interest and other income and income tax expense into a separate line item on the consolidated statements of income. The reclassification did not have an impact on net income or earnings per share.

2. Accounting Pronouncements

Recently Adopted

Business Combinations In December 2007, the Financial Accounting Standards Board (FASB) issued new guidance on business combinations which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This new guidance is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Noncontrolling Interests Also in December 2007, the FASB issued new guidance on noncontrolling interests in consolidated financial statements which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent s equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently as equity transactions. This new guidance was effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Derivatives and Hedging Disclosures In March 2008, the FASB issued new guidance on disclosures about derivative instruments and hedging activities which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity s financial position, financial performance and cash flows. The guidance amends and expands previous disclosure requirements for derivative instruments and hedging activities, including disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. This new guidance was effective for fiscal years and interim periods beginning after Nov. 15, 2008. Xcel Energy implemented the guidance on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 10 to the consolidated financial statements.

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Interim Fair Value Disclosures In April 2009, the FASB issued new guidance on interim disclosures about fair value of financial instruments which requires that disclosures regarding the fair value of financial instruments be included in interim financial statements. This new guidance was effective for interim periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and the required disclosures, see Note 11 to the consolidated financial statements.

Fair Value in Inactive Markets Also in April 2009, the FASB issued new guidance for identifying market transactions that are not orderly and determining fair value when market trading activity has decreased significantly. The new guidance emphasizes that even if there has been a significant decrease in the volume and level of market activity for an asset or liability, fair value still represents the exit price in an orderly transaction between market participants. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Other-Than-Temporary Impairments Additionally in April 2009, the FASB issued new guidance on recognition and presentation of other-than-temporary impairments which changes the method for determining whether an other-than-temporary impairment exists for debt securities, and also requires additional disclosures regarding other-than-temporary impairments. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Subsequent Events In May 2009, the FASB issued new guidance on subsequent events which establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The guidance is consistent with the auditing literature historically used for accounting and disclosure of subsequent events, however, it requires an entity to disclose the date through which subsequent events have been evaluated. This new guidance was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented the guidance on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Accounting Standards Codification In June 2009, the FASB issued *Topic 105 Generally Accepted Accounting Principles Amendments Based on Statement of Financial Accounting Standards No. 168 The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles (Accounting Standards Update (ASU) No. 2009-01)*, which updates the FASB Accounting Standards Codification (ASC or Codification) to state that the Codification is to be the single source of authoritative GAAP, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification is to be considered non-authoritative. The updates to the Codification contained in ASU No. 2009-01 were effective for interim and annual periods ending after Sept. 15, 2009. Xcel Energy implemented the guidance set forth by ASU No. 2009-01, recognizing the Codification as the single source of authoritative GAAP, other than the guidance put forth by the SEC, on July 1, 2009. The implementation did not have a material impact on Xcel Energy s consolidated financial statements.

Recently Issued

Postretirement Benefit Plans In December 2008, the FASB issued new guidance on employers disclosures about postretirement benefit plan assets. The guidance will amend and expand previous disclosure requirements for plan assets of a defined benefit pension or other postretirement plan to include investment policies and strategies, major categories of plan assets, information regarding fair value measurements, and significant concentrations of credit risk. This new guidance is effective for disclosures for fiscal years ending after Dec. 15, 2009. Xcel Energy does not expect the implementation of the guidance to have a material impact on its consolidated financial statements.

Consolidation of Variable Interest Entities In June 2009, the FASB issued new guidance on consolidation of variable interest entities. The guidance will significantly affect various elements of consolidation under existing accounting standards, including the determination of whether an entity is a variable interest entity and whether an enterprise is a variable interest entity s primary beneficiary. This new guidance is effective for fiscal years beginning after Nov. 15, 2009. Xcel Energy is currently evaluating the impact of this guidance on its consolidated financial statements.

Fair Value of Liabilities In August 2009, the FASB issued *Fair Value Measurements and Disclosures (Topic 820) Measuring Liabilities at Fair Value (ASU No. 2009-05)*, which will update the Codification with clarifications for measuring the fair value of liabilities. The liability-specific guidance includes clarifications and guidelines for using, when available, the most observable prices in active markets for identical liabilities or similar liabilities, or the prices of identical liabilities or similar liabilities traded as assets, rather than more complex and less observable valuation techniques and inputs such as those used in a present value model. The updates to the Codification contained in ASU No. 2009-05 are effective for interim and annual periods beginning after its August, 2009 issuance. Xcel Energy does not expect the implementation of these changes in the Codification to have a material impact on its consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)		Sept. 30, 2009		Dec. 31, 2008
Accounts receivable, net				
Accounts receivable	$	693,419	$	965,020
Less allowance for bad debts		(57,856)		(64,239)
	$	635,563	$	900,781
Inventories				
Materials and supplies	$	173,674	$	158,709
Fuel		214,792		227,462
Natural gas		166,463		280,538
	$	554,929	$	666,709
Property, plant and equipment, net				
Electric plant	$	22,650,906	$	21,601,094
Natural gas plant		3,231,528		3,004,088
Common and other property		1,491,664		1,497,162
Construction work in progress		1,688,560		1,832,022
Total property, plant and equipment		29,062,658		27,934,366
Less accumulated depreciation		(10,843,820)		(10,501,266)
Nuclear fuel		1,711,047		1,611,193
Less accumulated amortization		(1,415,093)		(1,355,573)
	$	18,514,792	$	17,688,720

4. Discontinued Operations

Results of operations for divested businesses and the results of businesses held for sale are reported, for all periods presented, as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale have been reclassified to assets and liabilities held for sale in the consolidated balance sheets. 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 held for sale and related to discontinued operations are as follows:

(Thousands of Dollars)		Sept. 30, 2009		Dec. 31, 2008
Cash	$	8,656	$	10,645
Deferred income tax benefits		91,174		39,422
Other current assets		28,210		6,574
Current assets held for sale and related to discontinued operations	$	128,040	$	56,641
Deferred income tax benefits	$	117,217	$	150,912
Other noncurrent assets		13,074		30,544
Noncurrent assets held for sale and related to discontinued operations	$	130,291	$	181,456
Accounts payable	$	680	$	760
Other current liabilities		27,378		6,169
Current liabilities held for sale and related to discontinued operations	$	28,058	$	6,929

Noncurrent liabilities held for sale and related to discontinued operations	$	3,279	$	20,656

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5. Income Taxes

Xcel Energy files a consolidated federal income tax return and 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.

Federal Audit In the first quarter of 2008, the Internal Revenue Service (IRS) completed an examination of Xcel Energy s federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. Tax year 2004 is the earliest open year and the statute of limitations applicable to Xcel Energy s 2004 federal income tax return remains open until Dec. 31, 2009. The IRS commenced an examination of tax years 2006 and 2007 in the third quarter of 2008, and this audit is expected to be completed in the first quarter of 2010. As of Sept. 30, 2009, the IRS had not proposed any material adjustments to tax years 2006 and 2007.

State Audits In the first quarter of 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an income tax audit through tax year 2005. No material adjustments were proposed for these state audits. As of Sept. 30, 2009, 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	Earliest Open Tax Year in Which an Audit Can Be Initiated
Colorado	2004
Minnesota	2004
Texas	2004
Wisconsin	2004

There currently are no state income tax audits in progress.

Unrecognized Tax Benefits The amount of unrecognized tax benefits reported in continuing operations was $40.8 million on Sept. 30, 2009 and $35.5 million on Dec. 31, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $6.6 million on both Sept. 30, 2009 and Dec. 31, 2008. The unrecognized tax benefit amounts reported in continuing operations were reduced by the tax benefits associated with NOL and tax credit carryovers of $13.2 million on Sept. 30, 2009 and $13.1 million on Dec. 31, 2008. The unrecognized tax benefit amounts reported in discontinued operations were reduced by the tax benefits associated with NOL and tax credit carryovers of $31.7 million on Sept. 30, 2009 and $26.5 million on Dec. 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $8.8 million and $9.2 million of tax positions on Sept. 30, 2009 and Dec. 31, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $32.0 million and $26.3 million of tax positions on Sept. 30, 2009 and Dec. 31, 2008, respectively, 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 effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The increase in the unrecognized tax benefit balance reported in continuing operations of $7.3 million from June 30, 2009 to Sept. 30, 2009, was due 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 as the IRS audit progresses and when state audits resume. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefits in continuing operations could decrease up to approximately $20 million.

The liability for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryovers. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the third quarter of 2009 was $0.7 million. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the third quarter of 2008 was $0.3 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $2.9 million on Sept. 30, 2009 and $1.9 million on Dec. 31, 2008. The amount reported within interest charges related to unrecognized tax benefits in discontinued operations in the third quarter of 2009 reduced interest expense by $0.6 million. The amount reported within interest charges related to unrecognized tax benefits in discontinued operations in the third quarter of 2008 reduced interest expense by $0.2 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $2.4 million on Sept. 30, 2009 and $1.5 million on Dec. 31, 2008.

No amounts were accrued for penalties as of Sept. 30, 2009 or Dec. 31, 2008.

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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, 2008 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference. The following discussion includes unresolved proceedings that are material to Xcel Energy s financial position.

NSP-Minnesota

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

Base Rate

NSP-Minnesota Electric Rate Case In November 2008, NSP-Minnesota filed a request with the MPUC to increase Minnesota electric rates by $156 million annually. This request was later modified to $136 million.

In September 2009, the MPUC voted to approve a rate increase of approximately $91.4 million. As part of its decision, the MPUC approved a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation and decommissioning expenses, effective Jan. 1, 2009. This decision reduced NSP-Minnesota s overall revenue deficiency by approximately $40 million, while at the same time reducing expense accruals by a corresponding amount. A summary of the key terms is listed below:

	Revised Request	Approved
Rate increase	$ 136 million	$ 91 million
Return on equity	11.0%	10.88%
Equity ratio	52.5%	52.5%
Electric rate base	$ 4.1 billion	$ 4.1 billion
Depreciation life extension for Prairie Island nuclear plant	0 years	10 years

As of Sept. 30, 2009, NSP-Minnesota accrued a customer refund of approximately $30.2 million to reflect the difference between interim rates that were implemented Jan. 2, 2009 and the amount approved by the MPUC. The written order was issued Oct. 23, 2009.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider The MPUC has approved a TCR rider, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. In October 2008, NSP-Minnesota submitted its proposed revised TCR rate factors, seeking to recover $14 million in 2009. A portion of amounts previously collected through the TCR rider prior to 2009 has been included for recovery in the NSP-Minnesota electric rate case described above. In June 2009, the MPUC approved the rider request. The revised TCR rate recovery factors were placed into effect in July 2009. In September 2009, NSP-Minnesota submitted its proposed revised rate factors, seeking to recover an additional $15.6 million in TCR rates in 2010. The request is pending MPUC action.

Renewable Energy Standard (RES) Rider The MPUC has approved an RES rider to recover the costs for utility-owned projects implemented in compliance with the RES. Under the rider, NSP-Minnesota recovered approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm. In 2008, NSP-Minnesota submitted the RES rider for recovery of approximately $22 million in 2009 attributable to the Grand Meadow wind farm. In February 2009, the MPUC approved the rider request. The revised RES rate recovery factors were placed into effect in March 2009. In September 2009, NSP-Minnesota submitted its proposed revised rate factors, seeking to recover an additional $44.4 million in RES rates in 2010. The request is pending MPUC action.

Metropolitan Emissions Reduction Project (MERP) Rider In October 2008, NSP-Minnesota filed a proposed MERP rider for 2009 designed to recover costs related to MERP environmental improvement projects. Under this rider, NSP-Minnesota proposes to recover $113.7 million in 2009, an increase of approximately $18.1 million over 2008. New rates went into effect automatically on Jan. 1, 2009, as stipulated. MPUC approval is still pending. On Oct. 1, 2009, NSP-Minnesota filed its proposed MERP rider for 2010 designed to recover costs related to MERP environmental improvement projects of $116.7 million. These new rates are expected to go into effect automatically on Jan. 1, 2010. NSP-Minnesota received comments on its 2009 MERP rider on Oct. 19, 2009, recommending the MPUC approve the 2009 proposed rates.

State Energy Policy (SEP) Rider In March 2009, NSP-Minnesota filed a proposed SEP rider for 2009 designed to recover costs related to state energy policy mandates and a cast iron natural gas pipe replacement project that is intended to reduce greenhouse gas (GHG) emissions. Under this rider, NSP-Minnesota proposes to recover approximately $2.5 million from its electric customers and

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$0.1 million from its natural gas customers in 2009. In September 2009, the MPUC approved the rider request. The revised SEP rate recovery factors were placed into effect in October 2009.

Annual Automatic Adjustment Report for 2007/2008 In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, $848.5 million in fuel and purchased energy costs, including $258.8 million of Midwest Independent Transmission System Operator, Inc. (MISO) charges, were recovered from Minnesota electric customers through the fuel clause adjustment (FCA). In addition, approximately $680 million of purchased natural gas and transportation costs were recovered through the purchased gas adjustment (PGA). NSP-Minnesota received comments on its 2008 electric annual automatic adjustment report in August 2009, which sought clarifications in the areas of transmission maintenance expenses, MISO revenue neutrality uplift charges and costs, and contractor non-performance responsibility for replacement energy costs. NSP-Minnesota received comments on its 2008 natural gas annual automatic adjustment report in June 2009, which recommends that the MPUC accept the 2008 report and PGA true up, and authorize its implementation. MPUC approval of both reports is pending.

Annual Automatic Adjustment Report for 2008/2009 In September 2009, NSP-Minnesota filed its annual 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 FCA. In addition, approximately $499.4 million of purchased natural gas and transportation costs were recovered through the PGA. MPUC approval is pending.

Conservation Incentive Filing Minnesota state agencies convened a work group to review the current energy efficiency incentive mechanism. The work group reached a consensus in the spring of 2009 that a shared savings model was the best structure for incenting cost-effective conservation. In July 2009, NSP-Minnesota filed its proposed incentive plan for achieving significantly higher demand side management (DSM) goals. The incentive would allow for sharing of savings of up to 15 percent of the net present value of benefits, depending on the level of savings achieved. NSP-Minnesota received comments on its proposed incentive mechanism in September 2009, which recommended minor modifications that do not significantly impact the potential award scale. An MPUC decision on the proposed plan is pending.

Gas Meter Module Failures Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, N.D. area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function. In 2008, NSP-Minnesota rebilled approximately 5,000 of these customers for their estimated consumption and then ceased rebilling as both the MPUC and North Dakota Public Service Commission (NDPSC) opened investigations into this matter. NSP-Minnesota has initiated dispute resolution with its provider of the AMR modules and meter reading services.

Pursuant to the NDPSC-approved plan, which provided customers with a $50 service quality credit for each customer experiencing a module failure NSP-Minnesota began implementing the service quality credits and the rebilling of remaining North Dakota customers in June 2009. In total, NSP-Minnesota rebilled North Dakota customers approximately $1.5 million for the estimated gas usage during the module failure period.

In March 2009, NSP-Minnesota filed with the MPUC for a proposed $50 service quality credit for each customer experiencing a module failure. On July 15, 2009, NSP-Minnesota filed an application to withdraw its request to rebill affected customers as too much time would have lapsed from the time of meter failures to the expected time (if approved) for rebilling. Although the MPUC order is still pending, the MPUC approved NSP-Minnesota s withdrawal of its request to rebill affected customers at its hearing in September 2009. NSP-Minnesota has determined that a number of AMR modules designed for commercial customers are defective and as a result is broadening efforts to evaluate the performance of both gas and electric AMR modules. As of Sept. 30, 2009, NSP-Minnesota has accrued an amount sufficient to cover the estimated impact.

Annual Review of Remaining Lives In February 2009, NSP-Minnesota filed a petition with the MPUC requesting an increase in proposed service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities and a depreciation study for other gas and electric assets, effective Jan 1, 2009. The Office of Energy Security (OES) recommended a 10-year lengthening of depreciation life of the Prairie Island nuclear plant. In July 2009, the MPUC approved the proposed service lives, salvage rates, and resulting depreciation rates effective Jan. 1, 2009, for plant in service, with the exception of the Prairie Island nuclear plant. The MPUC deferred the determination of the appropriate depreciation rates for the Prairie Island nuclear plant to the pending NSP-Minnesota electric rate case. In the electric rate case, the MPUC extended the depreciation life of the Prairie Island nuclear plant by 10 years beyond the current license life in light of NSP-Minnesota s application to extend the life of its nuclear plants by 20 years.

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Nuclear Decommissioning Expenses In June 2009, the MPUC issued its order in its review of NSP-Minnesota s 2009 nuclear plant decommissioning accruals. The order extended the decommissioning life for the Prairie Island nuclear plant by 10 years. The order reduced the amount of future nuclear decommissioning expenses that must be collected from customers from $32 million to zero, effective Jan. 1, 2009.

In August 2009, NSP-Minnesota filed a proposal with the MPUC to provide one-time refunds to return to customers their contributions of $22.8 million made to the external escrow decommissioning fund for the Monticello nuclear plant. In October 2009, NSP-Minnesota received comments on its proposed refund plan, which recommends approval with minor modifications to the proposed refund mechanics. MPUC action is pending.

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

South Dakota Electric Rate Case In June 2009, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $18.6 million annually, or 12.7 percent. This proposed increase includes approximately $2.9 million in revenues currently recovered through automatic recovery mechanisms. Thus, the requested increase, net of current automatic recovery mechanisms, is approximately $15.7 million or 10.7 percent. The request is based on a 2008 historic test year adjusted for known and measurable changes in rate base and operating and maintenance expenses, an electric rate base of $282 million, a requested return on equity (ROE) of 11.25 percent, and an equity ratio of 51.63 percent.

Rates may be implemented as early as January 2010, based on statutory requirements in South Dakota. The procedural schedule is as follows:

- Staff and intervenor testimony on Nov. 20, 2009;
- NSP-Minnesota rebuttal testimony on Dec. 4, 2009; and
- Technical and public hearings on Dec. 9 11, 2009.

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

Revenue Sufficiency Guarantee (RSG) Charges The MISO tariff charges certain market participants a real-time RSG charge, which is designed to ensure that any generator scheduled or dispatched by MISO will receive no less than its offer price for start-up, no-load and incremental energy. A proposal in 2005 by MISO to refine the RSG charge initiated protracted proceedings. In the subsequent compliance proceeding, the FERC has issued numerous orders, attempting to refine and clarify the RSG charge. With the issuance of these orders, the FERC has directed certain refunds to market participants, but has subsequently refined or waived various refund requirements. The FERC granted rehearing in part of certain earlier orders directing refunds to correct a rate mismatch in the RSG charge. Specifically, a June 2009 order waived refunds for the period from April 2005 to November 2007, and directed MISO to correct the rate mismatch (through refunds) from November 2007 to November 2008.

In August 2007, numerous parties filed complaints against MISO, arguing that the allocation of the RSG charge (only to certain market participants actually withdrawing energy) was unjust, unreasonable, and unduly discriminatory. After protracted proceedings, the FERC found in November 2008 that the RSG charge was unjust and unreasonable, and directed refunds. In May 2009, FERC granted rehearing in part regarding the applicability of refunds for the RSG charges. Specifically, the FERC determined that the refund-effective date is November 2008, the date of the FERC order determining that the allocation to market participants of the RSG charges was unjust and unreasonable.

The FERC directed MISO to implement an interim RSG cost allocation to be effective starting in August 2007. The FERC further directed MISO to submit a complete and final proposal, to be implemented on a prospective basis after the commencement of the MISO s ancillary services markets in January 2009. In February 2009, MISO submitted a filing to implement the new RSG rate design; however, the FERC has not yet rendered a final decision to implement the new rate design. Moreover, disputes have arisen regarding whether or not some resources should be assessed to the RSG under the interim rate. In August 2009, the FERC issued an order in which it invalidated numerous exemptions to the RSG that had previously been utilized by MISO through its business practice manuals. Several parties have sought rehearing and a final FERC decision is still pending.

Xcel Energy is a party to each of the relevant RSG-related proceedings. Each of the relevant RSG-related orders has been the subject of requests for rehearing at the FERC and petitions for review filed at the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The separate RSG proceedings have proceeded in parallel at the FERC, and the most recent orders (May, June and August 2009), are subject to pending requests for rehearing. The D.C. Circuit proceedings are being held in abeyance pending final action in the FERC proceedings.

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NSP-Wisconsin

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

Base Rate

2008 Electric Rate Case ***Nuclear Decommissioning Expenses*** In January 2008, the PSCW issued the final order in NSP-Wisconsin s 2008 test year rate case. The PSCW s final order included recovery of $8.7 million of annual nuclear decommissioning expenses, subject to refund, in anticipation of potential decreases in NSP-Minnesota s decommissioning expenses. NSP-Wisconsin and NSP-Minnesota share all NSP System generation and transmission costs, including nuclear decommissioning costs, by means of a FERC-approved tariff commonly referred to as the Interchange Agreement.

In June 2009, the MPUC issued the final order in its review of NSP-Minnesota s 2009 nuclear plant decommissioning accrual, and as a result of that order, the Wisconsin retail jurisdiction s share of annual nuclear decommissioning expenses decreased to approximately $1.4 million, effective January 2009. In accordance with the PSCW s final order, NSP-Wisconsin has established a refund liability of $5.5 million through September 2009.

The MPUC order also directed NSP-Minnesota to proceed with a filing to propose a method to return to customers their contributions made to the external escrow decommissioning fund for the Monticello nuclear plant. Once that plan is approved, NSP-Wisconsin will determine what steps are necessary to initiate a refund for its customers proportionate share of these funds. NSP-Wisconsin s share of these funds is approximately $5.8 million as of Sept. 30, 2009.

2010 Electric and Natural Gas Rate Case In June 2009, NSP-Wisconsin filed an electric and gas rate case in Wisconsin seeking an increase in retail electric rates of $30.4 million, or 5.7 percent, and proposed no change in natural gas rates. The request is based on an ROE of 10.75 percent, an equity ratio of 53.12 percent, an electric rate base of $644 million, a gas rate base of $81 million and a 2010 forecasted test year. The request is comprised of a traditional base rate increase of $45.1 million offset by projected fuel decreases of $14.7 million.

On Oct. 21, 2009, PSCW staff and intervenors filed testimony. The PSCW staff recommended an increase of $14.5 million for 2010 based on a 10.75 percent ROE and a 51.63 percent equity ratio. The PSCW staff has proposed to apply the 2009 fuel over recovery discussed in 2009 Electric Fuel Cost Recovery below against the increase such that there would be no change in rates for 2010. A summary of the proposed adjustments is listed below:

Millions of Dollars		**Request**		**PSCW Adjusted Request**
Base non-fuel	$	45.1	$	36.8
Fuel		(14.7)		(15.8)
Prairie Island decommissioning				(6.5)
Rate increase	$	30.4	$	14.5

The base non-fuel adjustments include: (1) an adjustment to the equity ratio from 53.12 percent to 51.63 percent on a regulatory basis; (2) a reduction to the rate base to account for appropriated retained earnings associated with certain hydro licenses; (3) reduced interchange agreement fixed charge billings and (4) a disallowance of certain employee compensation expenses. In addition, the PSCW staff adjustments to the proposed increase include a $6.5 million reduction for Prairie Island nuclear plant decommissioning expense as a result of the 10-year life extension approved by the MPUC.

The Wisconsin Industrial Energy Group (WIEG) filed direct testimony objecting to NSP-Wisconsin s class cost of service study and proposed rate design and recommended changes that would benefit its members.

A decision is expected by the end of 2009 with new rates in effect in January 2010. The procedural schedule is as follows:

- NSP-Wisconsin rebuttal testimony on Nov. 6, 2009;
- Surrebuttal testimony on Nov. 10, 2009; and
- Technical and public hearing on Nov. 11, 2009.

Other

2009 Electric Fuel Cost Recovery NSP-Wisconsin s fuel and purchased power costs for February 2009 were lower than authorized and outside the variance ranges for monitored fuel costs established by the PSCW. In April 2009, the PSCW opened a proceeding to

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determine if a rate reduction, or fuel credit factor, should be ordered. The PSCW set NSP-Wisconsin s electric rates subject to refund with interest at 10.75 percent, pending a full review of 2009 fuel costs.

NSP-Wisconsin s actual fuel costs through September 2009 were approximately $19.1 million less than authorized, primarily due to lower load and lower market prices for fuel and purchased power. As noted above, the PSCW staff recommended that a portion of this amount be used to offset the 2010 rate increase. The PSCW has not yet completed its review of NSP-Wisconsin s 2009 fuel costs. However, based on actual fuel costs to date, NSP-Wisconsin has established a liability of $13.3 million for such amounts subject to refund collected through Sept. 30, 2009.

PSCo

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

Base Rate

PSCo 2009 Electric Rate Case   In November 2008, PSCo filed a request with the CPUC to increase Colorado electric rates by $174.7 million annually, or approximately 7.4 percent. The rate filing was based on a 2009 forecast test year, an electric rate base of $4.2 billion, a requested ROE of 11.0 percent and an equity ratio of 58.08 percent. PSCo s request included a return of approximately $40 million for construction work in progress (CWIP) associated with incremental expenditures on the Comanche Unit 3 since Jan. 1, 2007. PSCo does not record allowance for funds used during construction (AFDC) income for the months this return is actually received from customers.

In February 2009, parties filed answer testimony in the case. In March 2009, PSCo filed rebuttal testimony and revised its rate increase request to $159.3 million to reflect updated data. On April 22, 2009, a settlement agreement with the major parties was filed with the CPUC. The settlement provides for an overall $112.2 million increase in base rates, but does not provide for the specific resolution of many of the disputed issues such as ROE and capital structure. However, the settlement provides that incremental CWIP not included in existing rates for the Comanche Unit 3 be removed from rate base and that PSCo would be allowed to continue to record AFDC income on this balance until the Comanche Unit 3 is placed into service.

On May 27, 2009, the CPUC approved the settlement agreement and new rates went into effect on July 1, 2009. On Sept. 21, 2009, a citizen intervenor, Leslie Glustrom, filed suit against the CPUC in district court for appeal of the CPUC decision.

PSCo 2010 Electric Rate Case   On May 1, 2009, PSCo filed with the CPUC a request to increase Colorado electric rates by $180.2 million, or 6.8 percent, effective in 2010. The rate filing is based on a 2010 calendar year budget and includes a requested ROE of 11.25 percent, an electric net rate base of approximately $4.4 billion allocated to the Colorado electric retail jurisdiction and an equity ratio of 58.05 percent.

PSCo s rate request also proposes to shift all or a portion of the costs currently being recovered through the Air Quality Improvement Rider and the DSM Cost Adjustment into base rates. While this shift would add $108.1 million to base rates in addition to the $180.2 million annual revenue increase sought by PSCo, it would correspondingly remove $108.1 million from these riders, and result in no net increase or decrease on customer bills.

Intervenors have filed testimony with the following current recommendations:

- The CPUC staff has recommended an increase of approximately $70.5 million based on an adjusted 2008 historic test year and a 9.84 percent ROE. The CPUC staff recommended adjustments to the 2008 historic test year were costs associated with a full year of 2010 expenses for the Comanche Unit 3 project and Fort St. Vrain Units 5 and 6. The other staff adjustments were related to ROE, elimination of costs associated with PSCo s annual incentive compensation plan and deferral of recovery of dismantling costs associated with retiring plants until those costs are known. CPUC staff also recommended elimination of sharing for asset based energy sales (referred to as generation book sales).

- The Colorado Office of Consumer Counsel (OCC) has recommended an increase of approximately $33.2 million based on an adjusted 2008 historic test year and a 9.75 percent ROE. The OCC recommended adjustments to the 2008 historic test year were costs associated with a full year of 2010 expenses for the Comanche Unit 3 project (including related pollution control and transmission upgrades) and Fort St. Vrain Units 5 and 6. The other OCC adjustments are related to ROE, a lower equity ratio of 53 percent, a cash working capital cost reduction and additional revenue associated with unbilled revenue, elimination of incentive pay, lower pension and benefit costs, and no recovery of future Innovative Clean Technology (ICT) expense. The OCC recommended an increase of $87.8 million if a forecast test year is accepted. The OCC recommended that generation book

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margins be shared 95 percent to customers and 5 percent to shareholders and the inverse sharing for non-asset based or proprietary margins.

- Colorado Energy Consumers (CEC) recommended the use of an adjusted 2008 historic test year adjusted for major plant investments for the Comanche Unit 3 project and Fort St. Vrain Units 5 and 6; and an ROE of 10.0 percent, resulting in an increase of $95.4 million, which should be reduced to reflect any appropriate adjustments recommended by other intervenors.

- CF&I Steel (CF&I) and Climax Molybdenum Company (Climax) recommended the use of an adjusted 2008 historic test year adjusted for major plant investments for the Comanche Unit 3 project and Fort St. Vrain Units 5 and 6; and an adjustment for 2008 bonus depreciation, resulting in an increase of $98.4 million, which should be reduced to reflect any appropriate adjustments recommended by other intervenors.

In October 2009, PSCo filed rebuttal testimony and revised their request rate increase to $177.4 million and affirmed its requested ROE of 11.25 percent. The procedural schedule is as follows.

- Hearings on the merits on Oct. 26 Nov. 6, 2009; and
- Statements of Position on Nov. 16, 2009.

PSCo expects a decision before year end with new rates effective in January 2010.

Transmission Cost Adjustment (TCA) Rider In December 2007, the CPUC approved PSCo s application to implement a TCA rider. PSCo filed its annual update to the TCA rider in November 2008, and new rates went into effect on Jan. 1, 2009, to recover approximately $18.0 million on an annual basis until the rates in the 2009 rate case take effect. Coincident with the implementation of new electric rates on July 1, 2009, approximately $16.0 million from the TCA rider were included in base rates with a corresponding reduction in the TCA rider.

Pending and Recently Concluded Regulatory Proceedings FERC

Pacific Northwest FERC Refund Proceeding In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding administrative law judge (ALJ) concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC s orders in this proceeding with the U. S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Court of Appeals remanded the proceeding back to the FERC. The Court of Appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Court of Appeals denied a petition for rehearing in April 2009, and the mandate was issued. The FERC has yet to act on this order on remand; currently, certain motions concerning procedures on remand are pending before the FERC.

SPS

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

Base Rate

Texas Retail Base Rate Case In June 2008, SPS filed a rate case with the PUCT seeking an annual rate increase of approximately $61.3 million, or approximately 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue would decline by $33.1 million, primarily due to fuel savings from the Lea Power Partners (LPP) purchase power agreement.

The rate filing was based on a 2007 test year adjusted for known and measurable changes, a requested ROE of 11.25 percent, an electric rate base of $989.4 million and an equity ratio of 51.0 percent. Interim rates of $18 million for costs associated with the LPP power purchase agreement went into effect in September 2008.

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In January 2009, a settlement agreement was reached with various intervenors, which provided for a base rate increase of $57.4 million, a reduced depreciation expense of $5.6 million, allowed SPS to implement the transmission rider in 2009 and precludes SPS from filing to seek any other change in base rates until Feb. 15, 2010. In January 2009, an ALJ approved interim rates effective February 2009. On June 2, 2009, the PUCT issued its order approving the settlement.

John Deere Wind Complaint In June 2007, several John Deere Wind Energy subsidiaries (JD Wind) filed a complaint against SPS disputing SPS payments for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind are appropriate and in accordance with SPS filed tariffs with the PUCT. In March 2009, the ALJ recommended that SPS payment methodology to JD Wind is proper and that JD Wind s complaint be denied.

In May 2009 the PUCT issued a final order denying JD Wind s request for relief against SPS. In June 2009, JD Wind filed a petition for review of the final order in Texas District Court. In July 2009, the PUCT filed an answer to JD Wind s petition in Texas District Court in which the PUCT denied each and every, all and singular, the allegations contained in the JD Wind petition.

In September 2009, JD Wind submitted a petition to the FERC, which in effect, disputed and sought to overturn the decision of the PUCT. SPS has responded to the JD Wind petition, asserting among other things that the dispute should be resolved in Texas courts.

Texas Jurisdictional Fuel Allocation Methodology In May 2009, SPS filed an application to revise the calculation of Texas retail jurisdictional fuel and purchased power expense, effective in January 2008. SPS has determined that its current method results in a material amount of unrecovered fuel and purchased power expense. The application seeks approval for a revised methodology, which matches the fuel and purchased power expenses in a month with the fuel factor revenue received from each kilowatt hour used that month. In July 2009, the PUCT referred this case to the State Office of Administrative Hearings (SOAH) for a contested case hearing.

In August 2009, the PUCT issued a draft of the preliminary order. The draft adopts SPS position that the PUCT should consider the fuel allocation methodology in this case; lists various issues for the case, most of which are the issues identified in SPS filing and lists certain issues that are not to be addressed in this case, specifically, SPS fuel factor, the formula used to set SPS fuel factor, and the reasonableness of SPS fuel and purchased power costs. In August 2009, the PUCT approved the preliminary order as drafted. A procedural schedule was established in September 2009, however, that schedule has been delayed to allow for settlement discussions.

In late October 2009, SPS filed a unanimous settlement that would allow for the change in the calculation of deferred fuel consistent with the approach proposed by SPS. Approval by the PUCT is pending. If approved, the estimated impact is expected to result in an approximate $5.9 million increase to fuel and purchased power expenses for the Texas retail jurisdiction for the Jan. 1, 2008 to Dec. 31, 2009 period. SPS has agreed to reduce the new allocated portion by $3 million subsequent to adopting the new methodology going forward.

Texas Transmission Cost Recovery Factor (TCRF) In June 2009, SPS filed a request to implement a TCRF with proposed revenues of $7.4 million annually. The TCRF filing is based on changes in transmission investment for the period of Jan. 1, 2008 through April 30, 2009 and increases in FERC approved transmission costs for 2008. In 2007, the PUCT implemented rules allowing utilities to request a TCRF in between rate cases for recovery of new transmission investment costs. This is SPS first filing under that rule. In July 2009, the PUCT referred this case to the SOAH for a contested case proceeding. SPS anticipates the PUCT will issue an order with rates effective by the end of 2009.

On Oct. 22, 2009, intervenors filed testimony and made the following recommendations. The Texas Industrial Energy Consumers recommended a revenue requirement of $3.5 million and the Alliance of Xcel Municipalities recommended a revenue requirement of $3.1 million.

The current procedural schedule is as follows:

- PUCT staff testimony on Oct. 29, 2009;
- SPS rebuttal testimony on Nov. 5, 2009
- Settlement and rehearing conferences on Nov. 10 Nov. 12, 2009; and
- Hearing on the merits on Nov. 17 Nov. 19, 2009.

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Pending and Recently Concluded Regulatory Proceedings New Mexico Public Regulation Commission (NMPRC)

Base Rate

2008 New Mexico Retail Electric Rate Case In December 2008, SPS filed with the NMPRC a request to increase electric rates in New Mexico by approximately $24.6 million, or 6.2 percent. The request was based on a historic test year (split year based on the year ending June 30, 2008), an electric rate base of $321 million, and an equity ratio of 50.0 percent and a requested ROE of 12.0 percent. SPS also requested interim rates of $7.6 million per year to recover capacity costs of the Lea Power facility, which became operational in September 2008.

In March 2009, the NMPRC approved a partial stipulated settlement between the parties that allows SPS to recover approximately $5.7 million of interim rates, effective May 1, 2009, through an LPP cost rider until the final rates from the remainder of the case are effective.

In May 2009, the parties filed an uncontested stipulation that resolves all issues in the case. Under the stipulation, SPS receives a base rate increase of $14.2 million, effective July 1, 2009. SPS has agreed that Dec. 1, 2010 is the earliest date it will file its next base rate case, subject to a force majeure provision triggered by additional environmental compliance costs.

In July 2009, the NMPRC issued an order approving the stipulation agreement. SPS implemented the new rates on July 15, 2009.

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.

In May 2006, a FERC ALJ found that SPS should recalculate its fuel and purchased economic energy cost adjustment clause (FCAC) billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by deducting the incremental fuel costs attributed to SPS sales of capacity and energy to other wholesale customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales made out of temporarily excess capacity. In addition, the ALJ made recommendations on a number of base rate issues including a 9.64 percent ROE.

Golden Spread Complaint Settlement In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. In April 2008, the FERC approved the Settlement, which resolved all issues that were the subject of the Complaint; implemented a formula rate and extended the term of its partial requirements sale to Golden Spread beginning 2012 at 500 MW and ramping down to 200 MW at the end of the new term in 2019. The Settlement made the extended purchase contingent on certain state approvals. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals. The approvals are currently pending before the NMPRC and the PUCT.

Order on Wholesale Rate Complaints 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 requires certain refunds.

- **Base Rates**: The FERC determined the ROE should be 9.33 percent and the treatment of market based rate contracts should be to credit revenues to the cost of service rather than allocating costs to the agreements. The revenue requirement established by the FERC results are estimated to be approximately $25 million, or approximately $6.9 million below the level charged to these customers during this 18-month period. Rates for full requirements customers, the New Mexico Cooperatives and Cap Rock, as well as an interruptible contract with PNM for the period beginning July 1, 2006, are the subject of settlements that have either been approved or are pending before the FERC.

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- **Fuel Clause**: The FERC determined that the method for calculating fuel and purchased energy charges to the complaining customer is to deduct from such costs incremental fuel and purchased energy costs, which it is attributing to SPS market based intersystem sales on the basis that these are opportunity sales. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005. While the order is subject to interpretation with respect to the calculation of the refund obligation, SPS does not expect its refund obligation to its full requirements customers from Jan. 1, 2005 through March 31, 2008, to exceed $11 million. PNM has filed a separate complaint that any refund obligation to PNM will be determined in that docket.

Several parties, including SPS, filed requests for rehearing on the order. These requests are pending before the FERC. 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 have protested the calculations. Once the final refund amounts are approved by the FERC, interest will be added to the refund due to the full requirements customers. As of Sept. 30, 2009, SPS has accrued an amount sufficient to cover the estimated refund obligation.

On June 5, 2009, SPS, the New Mexico Cooperatives and Cap Rock filed a letter with FERC indicating that the parties had reached an agreement in principle regarding this matter and asked that the FERC not issue an order upon reconsideration to allow the parties an opportunity to formalize the Settlement and file it with the NMPRC. The parties have filed subsequent letters with the FERC requesting that it not take up their reconsideration requests as the parties continue to work to finalize the terms of the agreement.

SPS 2008 Wholesale Rate Case In March 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE.

In May 2008, the FERC conditionally accepted and suspended the rates and established hearing and settlement procedures. The FERC granted a one-day suspension of rates instead of 180 days. Lea Power achieved commercial operations in September 2008 and the proposed base rates of $9.9 million, based on a 10.25 percent ROE and a 12 coincident peak demand allocator, became effective, subject to refund.

In April 2009, the parties reached a settlement in which SPS will receive an annual revenue increase of approximately $9.6 million or an overall percentage increase of 3.3 percent. The FERC issued an order approving the uncontested settlement in September 2009.

SPS 2008 Transmission Formula Rate Case In December 2007, Xcel Energy submitted an application to implement a transmission formula rate for the SPS zone of the Xcel Energy Open Access Transmission Tariff (OATT). The changed rates will affect all wholesale transmission service customers using the SPS transmission network under either the Southwest Power Pool, Inc. (SPP) Regional OATT or the Xcel Energy OATT.

As filed, SPS transmission rates would be updated annually each July 1 based on SPS prior year actual costs and loads plus the revenue requirements associated with projected current year transmission plant additions. The proposed ROE was 12.7 percent, including a 50 basis point adder for SPS participation in the SPP Regional Transmission Organization (RTO). The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC accepted the proposed rates, suspending the effective date to July 6, 2008, and setting the rate filing for hearings and settlement procedures. The FERC granted a 50 basis point adder to the ROE that it will determine in this proceeding as a result of SPS participation in the SPP RTO. The filed rates were placed into effect on July 6, 2008, subject to refund.

In July 2009, SPS and the parties reached a settlement in principle regarding all issues except the ratemaking and rate design treatment of certain radial transmission lines under the SPP Regional OATT. In September 2009, Xcel Energy, on behalf of SPS and the other parties to the proceeding, filed an uncontested offer of settlement and settlement agreement with the FERC which resolves all issues in the proceeding with the exception of the radial line issue.

The settlement provides for a formula rate using a fully forecasted test year effective Jan. 1, 2009, with a stated ROE of 11.27 percent (including the 50 basis point adder for SPP RTO participation), with rates for the locked in 2008 period established by settlement. The settlement will result in approximately $0.8 million in additional revenues for 2008 and 2009 in aggregate and will allow SPS to update its transmission rates annually for predicted costs and loads, subject to an annual true-up. In October 2009, the ALJ approved placing the settlement rates into effect on Oct. 1, 2009, subject to approval of the settlement, and certified the settlement for FERC approval as uncontested. The settlement is pending FERC approval. Additionally in October 2009, SPS announced the 2010 costs and charges pursuant to the formula rate and are expected to provide $2.7 million in additional revenue, subject to true-up.

On Sept. 25, 2009, the FERC set the issue of cost allocation for radial lines for hearings. The ALJ is scheduled to issue an initial decision in August 2010. The outcome of the litigation is not expected to have a material impact on SPS.

7. Commitments and Contingent Liabilities

Except to the extent noted below, 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, 2008, and Note 6 to the consolidated financial statements in this Quarterly Report on Form 10-Q 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 contingencies and unresolved contingencies that are material to Xcel Energy s financial position.

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, to which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At Sept. 30, 2009, the liability for the cost of remediating these sites was estimated to be $103.1 million, of which $7.2 million was considered to be a current liability.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant 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. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until late 2009 or 2010. In October 2004, the state of Wisconsin filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The state also alleges a claim for forfeitures and interest. This litigation was resolved in the first quarter of 2009, and all costs paid to the state are expected to be recoverable in rates.

In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007. In June 2007, the EPA modified its remedial investigation report to establish final remedial action objectives (RAOs) and preliminary remediation goals (PRGs) for the Ashland site. In October 2007, the EPA approved the series of reports included in the remedial investigation report. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup.

In 2008, NSP-Wisconsin spent $0.8 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. In December 2008, the EPA approved the final feasibility study submitted by NSP-Wisconsin. The final feasibility study sets forth a range of remedial options under consideration by the EPA for the site but does not select a remedy. In 2009, the EPA issued its proposed remedial action plan (PRAP). It is expected that the EPA will select a remedial action plan sometime in late 2009. The estimated remediation costs for the cleanup proposed by the EPA in the PRAP range between $94.4 million and $112.8 million.

In July 2009, NSP-Wisconsin advised the EPA and the Wisconsin Department of Natural Resources (WDNR) that it would not implement the hybrid dry dredging alternative proposed in the PRAP. NSP-Wisconsin stated that the EPA s hybrid alternative is 1) unsafe, 2) would cost at least $37 million more than conventional, wet dredging, and 3) would provide no environmental benefits over conventional dredging.

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In addition to potential liability for remediation, NSP-Wisconsin may also have 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.

NSP-Wisconsin s liability for 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 and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility. NSP-Wisconsin continues to work with the WDNR 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.

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.

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, 2008. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA s Proposed Greenhouse Gas Endangerment Finding On April 17, 2009, the EPA issued a proposed finding that GHGs threaten public health and welfare. This finding was in response to the U.S. Supreme Court s decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007), which held that GHGs are pollutants covered by the Clean Air Act (CAA) and required the EPA to determine whether emissions of GHGs from motor vehicles endanger public health or welfare. The EPA s proposed endangerment finding applies to the CAA s mobile source program, and does not automatically trigger regulation under other provisions of the CAA that are applicable to stationary sources, such as power plants. As such, the proposed endangerment finding, in and of itself, does not impact Xcel Energy or its operating subsidiaries.

Clean Air Interstate Rule (CAIR) In March 2005, the EPA issued the CAIR to further regulate sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions. The objective of CAIR was 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 July 2008, the U. S. Court of Appeals for the District of Columbia vacated CAIR and remanded the rule to EPA. On Dec. 23, 2008, the court reinstated CAIR while the EPA develops new regulations in accordance with the court s July opinion. The EPA has indicated that a CAIR replacement rule will be proposed in early 2010 with finalization planned for early 2011.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

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 capital investments for NOx controls in the SPS region are estimated at $4.5 million. For 2009, the estimated NOx allowance compliance costs are $0.8 million to $1.0 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.

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On May 12, 2009, the EPA issued a proposed rule to stay the effectiveness of CAIR in Minnesota. NSP-Minnesota expects the EPA to complete this regulatory action before 2009 NOx allowances must be surrendered in February 2010. As such, cost estimates are not included at this time for NSP-Minnesota. For 2009, the estimated NOx allowance costs for NSP-Wisconsin are $0.3 million.

Allowance cost estimates for SPS and 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.

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 impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. The EPA is in the process of developing a Maximum Achievable Control Technology (MACT) rule to replace CAMR. The EPA is expected to propose the new MACT rule for electric generating units in 2010. Costs to comply with the Minnesota Mercury Emissions Reduction Act of 2006 are discussed in the following sections.

In Colorado, the Air Quality Control Commission (AQCC) passed a mercury rule, which requires 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 absorbent 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. Xcel Energy installed and is operating and maintaining continuous mercury emission monitoring systems at these generating facilities.

In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. In November 2008, NSP-Minnesota filed a request with the MPUC to reflect its requested recovery of these emission reduction compliance costs incurred through 2009 in the NSP-Minnesota electric rate case. In June 2009, NSP-Minnesota received an order from the MPUC closing the docket to correspond with the inclusion of costs in the electric rate case. The recovery of the costs was allowed as part of the rate case.

In November 2008, the MPUC approved and ordered the implementation of the Sherco Unit 3 and A. S. King mercury emission reduction plans. The approved plans are to install a sorbent injection system at both A. S. King and Sherco Unit 3. Implementation would occur by Dec. 31, 2009 at Sherco Unit 3 and by Dec. 31, 2010 at A. S. King. In July 2009, NSP-Minnesota filed a petition with the MPUC requesting to establish a mercury cost recovery rider with 2010 adjustment factors that would recover the 2010 revenue requirement of $3.5 million associated with these two projects from customers.

In the fourth quarter of 2009, NSP-Minnesota expects to file plans for mercury control at Sherco Units 1 and 2 with the MPUC and the Minnesota Pollution Control Agency (MPCA). Assuming these plans are approved, NSP-Minnesota expects to file for recovery of the costs to implement these plans through the mercury cost recovery rider.

Regional Haze Rules In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule 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, NOx and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. PSCo estimates that the remaining cost for implementation of BART emission control projects is approximately $141 million in capital costs, which are included in the capital budget.

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 has been submitted to the EPA for approval. In January 2009, the Colorado Air Pollution Control Division (CAPCD) initiated a joint stakeholder process to evaluate 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 have a final plan for additional point-source NOx controls by the end of 2010.

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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. On Nov. 13, 2008, NSP-Minnesota submitted a revised BART alternatives analysis letter to the MPCA to account for increased construction and equipment costs. The underlying conclusions and proposed emission control equipment, however, remain unchanged from the original 2006 BART analysis. The MPCA completed their BART determination and proposed SO2 and NOx limits in the draft state implementation plan (SIP) that are equivalent to the reductions made under CAIR.

In response to a petition from several environmental groups, the U.S. Department of Interior certified on Oct. 21, 2009, that a portion of the visibility impairment in Voyageurs and Isle Royal National Parks is reasonably attributable to emissions from Sherco Units 1 and 2. The MPCA determined, however, that this certification does not alter the proposed SIP. The SIP proposes BART controls for Sherco 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. The MPCA will now work with the MPCA Citizens Board for approval of the SIP, which will then be submitted to the EPA for approval before the end of 2009.

Federal Clean Water Act The federal Clean Water Act 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 in the United States Court of Appeals for the Second Circuit (Court of Appeals) challenging the phase II rulemaking. In January 2007, the Court of Appeals issued its decision and remanded the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state s best professional judgment until the EPA is able to fully respond to the remand. In April 2008, the U.S. Supreme Court granted limited review of the Court of Appeals opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. On April 1, 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 to the Court of Appeals decision, 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.

The MPCA exercised its authority under best professional judgment to require the Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake s impact on aquatic wildlife. NSP-Minnesota is discussing alternatives with the local community and regulatory agencies to address this concern.

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.

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 is a wholly owned subsidiary of Xcel Energy. Among other things, 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 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*

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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 Hartford 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 United States 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 January 2009, the parties reached a settlement agreement in principle 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 in principle will not have a material financial effect upon Xcel Energy. Per court order, discovery in most of the remaining cases must be completed by Dec. 5, 2009. Trial for all cases venued in Nevada will likely be set for 2010.

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 have filed an appeal.

In late 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 defendants, including Xcel Energy, e prime and NSP-Wisconsin. In September 2009, Plaintiffs moved to consolidate the Newpage and Arandell matters. Defendants have filed motions to dismiss and, as with *Arandell*, Xcel Energy, e prime and NSP-Wisconsin believe the allegations asserted against them are without merit and they intend to vigorously defend against the asserted claims.

Environmental Litigation

Carbon Dioxide (CO_2) Emissions Lawsuit In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court 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 as defined under state and federal common law because it has contributed to global warming. 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. In October 2004, Xcel Energy and the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the court granted the motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit. In June 2007, the Court of Appeals issued an order requesting the parties to file a letter brief regarding the impact of the United States Supreme Court s decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in *Massachusetts v. EPA*, the United States Supreme Court held that CO_2 emissions are a pollutant subject to regulation by the EPA under the CAA. In July 2007, in response to the request of the Court of Appeals, the defendant utilities filed a letter brief stating the position that the United States Supreme Court s decision supports the arguments raised by the utilities on appeal. On Sept. 21, 2009, the Court of Appeals issued an opinion reversing the lower court decision. Xcel Energy intends to file a petition for rehearing or rehearing en banc on or before Nov. 5, 2009.

Comer vs. Xcel Energy Inc. et al. In April 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 in support of their claim, several legal theories, including 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. In September 2007, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Fifth Circuit. Oral arguments were presented to the Court of Appeals on Aug. 6, 2008. Pursuant to the court s order of Sept. 26, 2008, re-argument was held on Nov. 3, 2008. On Oct. 16, 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. It is anticipated that Xcel Energy will file a petition for rehearing or rehearing en banc.

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utilities, oil, gas and coal companies. The suit was brought on behalf of approximately 400 native Alaskans, the Inupiat Eskimo, who claim that defendants emission of CO2 and other GHGs contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence,

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the entire village must be relocated at a cost of between $95 million and $400 million. Plaintiffs assert a nuisance claim under federal and state common law, as well as a claim asserting   concert of action   in which defendants are alleged to have engaged in tortious acts in concert with each other. Xcel Energy was not named in the civil conspiracy claim. 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. On Oct. 15, 2009, the U.S. District Court dismissed the lawsuit on constitutional grounds. It is unknown whether plaintiffs intend to appeal this decision.

Comanche Unit 3 Clean Air Act Lawsuit   WildEarth Guardians (WEG) has filed a lawsuit 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 has 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. On Oct. 28, 2009, WEG filed a motion for a preliminary injunction, seeking to enjoin PSCo from constructing, modifying, or operating Comanche Unit 3 prior to receiving a final MACT determination. PSCo strongly opposes the injunction. Among other issues, PSCo believes that WEG has failed to establish a substantial likelihood of prevailing on the merits of the suit and that therefore there is no valid legal basis upon which an injunction should be issued.

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy   In June 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. After its motion to dismiss plaintiffs   claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007, the court granted NSP-Minnesota s motion for certification, and oral arguments took place on Sept. 11, 2008. Mediation took place on Oct. 14, 2008, but the matter was not resolved. 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 on Feb. 17, 2009. All briefs have been filed, but the Court has not yet set a date for oral argument.

Qwest vs. Xcel Energy Inc.   In June 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. Pursuant to this agreement, Qwest asserted PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. In May 2006, PSCo filed a counterclaim against Qwest asserting Qwest had a duty to PSCo and an obligation under the contract to maintain its poles in a safe and serviceable condition. 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. On June 16, 2008, Qwest filed its appellate brief. On April 30, 2009, the Colorado Court of Appeals affirmed the jury verdict insofar as it relates to claims asserted by Qwest against PSCo. Qwest subsequently filed a petition for rehearing with the Colorado Court of Appeals. On May 28, 2009, the Colorado Court of Appeals denied Qwest s request for rehearing. Qwest s petition for certiorari to the Colorado Supreme Court was filed June 26, 2009. PSCo s response brief was filed on July 27, 2009. The matter has been fully briefed, and PSCo is awaiting a ruling from the Colorado Supreme Court.

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 LaCrosse, 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. The Wisconsin action remains in abeyance.

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 (Ranger), TIG Insurance Company (TIG), Royal Indemnity Company and Globe Indemnity Company.

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of 11 insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Minnesota Court of Appeals challenging the dismissal of these carriers.

On Aug. 25, 2009, the Minnesota Court of Appeals affirmed the district court decision. NSP-Wisconsin subsequently filed a petition for review of this decision with the Minnesota Supreme Court. It is uncertain when the Minnesota Supreme Court will rule on whether to grant review pursuant to the petition.

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.

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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. On Sept. 26, 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. In April 2008, the DOE asked the Court of Appeals to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court of Appeals granted the request. In December 2008, NSP-Minnesota made a motion in the Court of Appeals to lift the stay, which was denied by the Court of Appeals in February 2009. 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 s expert report on damages was submitted on April 15, 2009, and asserts damages in excess of $250 million. In late August 2009, the Court agreed to give the DOE an unspecified extension of time to clarify issues regarding NSP-Minnesota s claim and to file its expert report. Trial is expected to take place in 2010.

Mallon vs. Xcel Energy Inc. In August 2007, Xcel Energy, PSCo and PSR Investments, Inc. (PSRI) (hereafter 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 Corporate Owned Life Insurance (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. On June 23, 2008, Provident filed a motion to dismiss the complaint. On Oct. 22, 2008, the court granted Provident s motion in part, but denied the motion with respect to a majority of the core causes of action asserted by Plaintiffs. In September 2009, Plaintiffs reached a settlement with Mallon and TransFinancial Corporation. Pursuant to the terms of the agreement, Mallon agreed to pay Plaintiffs a specified amount and the parties agreed to mutually release each other from all claims. Plaintiffs continue to prosecute their claims against Provident. A trial concerning these claims is expected in early 2010.

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. This work was being performed as part of a corrosion prevention effort. A fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and 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 twenty-two 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 subsequently extended the stay to October 2009. 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 are not expected to 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.

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Stone & Webster, Inc. vs. PSCo **On July 14, 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 in Pueblo, Colo. Shaw, a contractor retained to perform certain engineering, procurement and construction work on Comanche Unit 3, alleges, among other things, that PSCo was responsible for and 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, including PSCo, 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, among other things, to liquidated damages and excess costs incurred. It is not anticipated that this lawsuit will affect Comanche Unit 3 s scheduled in-service date.**

Fru-Con Construction Corporation vs. Utility Engineering Corporation (UE) et al. In March 2005, Fru-Con Construction Corporation (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.

Lamb County Electric Cooperative (LCEC) In 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging SPS was unlawfully providing service to oil field customers in LCEC s certificated area. In May 2003, the PUCT issued an order denying LCEC s petition based on its determination that SPS in 1976 was granted a certificate to serve the disputed customers. LCEC appealed the decision to the Texas state court. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the decision to the Court of Appeals for the Third Supreme Judicial District. In November 2008, the Court of Appeals issued an opinion affirming the decision in favor of SPS. In December 2008, LCEC filed a petition for review with the Supreme Court of Texas. On Feb. 27, 2009, the Supreme Court of Texas denied LCEC s request for review.

In 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination of the legality of SPS providing electric service to the disputed customers. The PUCT order from May 2003, which found SPS was legally serving the disputed customers, collaterally determines the issue of liability contrary to LCEC s position in the suit. Because the PUCT May 2003 order has now been affirmed, on June 16, 2009, LCEC filed a motion to dismiss this case. On Sept. 16, 2009, the District Court entered a dismissal order, disposing of all claims that have been or could have been asserted in this case.

8. Short-Term Borrowings and Other Financing Instruments

Commercial Paper At Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $494.0 million and $330.3 million, respectively. The weighted average interest rates at Sept. 30, 2009 and Dec. 31, 2008 were 0.47 percent and 3.53 percent, respectively. At Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had combined board approval to issue up to $2.25 billion of commercial paper.

Credit Facility Bank Borrowings At Dec. 31, 2008, Xcel Energy and its subsidiaries had credit facility bank borrowings of $125.0 million with a weighted average interest rate of 1.88 percent. At Sept. 30, 2009, Xcel Energy and its subsidiaries had no credit facility bank borrowings.

Money Pool Xcel Energy and its utility subsidiaries have established a money pool arrangement that allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates. The money pool arrangement does not allow loans from the subsidiaries to the holding company. At Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had money pool loans outstanding of $117.0 million and $104.5 million, respectively. The money pool loans are eliminated upon consolidation. The weighted average interest rates at Sept. 30, 2009 and Dec. 31, 2008, were 0.50 percent and 3.48 percent, respectively.

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9. Long-Term Borrowings and Other Financing Instruments

On March 1, 2009, NSP-Wisconsin redeemed its 7.375 percent $65.0 million first mortgage bonds due Dec. 1, 2026. In addition to repayment of all principal amounts, NSP-Wisconsin paid accrued interest and a redemption premium totaling approximately $3.0 million.

On June 4, 2009, PSCo issued $400 million of 5.125 percent first mortgage bonds, series due 2019. PSCo added the proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the net proceeds to fund the payment at maturity of $200 million of 6.875 percent unsecured senior notes due July 15, 2009.

In 1999, WYCO was formed as a joint venture with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. In June 2009, having achieved certain phases of construction, WYCO s Totem gas storage facilities (Totem) were placed in service. WYCO will lease Totem to CIG, and CIG will operate the facilities, providing natural gas storage services to PSCo under a service arrangement that commenced on July 1, 2009.

Xcel Energy accounts for PSCo s service arrangement with CIG as a capital lease in accordance with the authoritative guidance on lease accounting. As a result, Xcel Energy recorded a $67 million capital lease obligation as of Sept. 30, 2009. WYCO is expected to incur approximately $20 million of additional construction costs to complete construction and make Totem operational at full storage capacity.

10. Derivative Instruments

Effective Jan. 1, 2009, Xcel Energy adopted new guidance on disclosures about derivative instruments and hedging activities contained in *ASC 815 Derivatives and Hedging*, which requires additional disclosures regarding why an entity uses derivative instruments, the volume of an entity s derivative activities, the fair value amounts recorded to the consolidated balance sheet for derivatives, the gains and losses on derivative instruments included in the consolidated statement of income or deferred, and information regarding certain credit-risk-related contingent features in derivative contracts.

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. See additional information pertaining to the valuation of derivative instruments in Note 12 to the consolidated financial statements.

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

At Sept. 30, 2009, accumulated other comprehensive income related to interest rate derivatives included $0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

At Sept. 30, 2009, Xcel Energy had an unsettled interest rate swap outstanding at SPS with a notional amount of $25 million. The interest rate swap is not designated as a hedging instrument, and as such, changes in the fair value for the interest rate swap are recorded to earnings.

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

At Sept. 30, 2009, Xcel Energy had various utility commodity and 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 other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on the commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the nine months ended Sept. 30, 2009 and 2008.

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At Sept. 30, 2009, Xcel Energy had $4.9 million of net losses in accumulated other comprehensive income related to utility commodity and vehicle fuel cash flow hedges of which $4.2 million is 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.

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

The following table shows the major components of derivative instruments valuation in the consolidated balance sheets:

	Sept. 30, 2009		Dec. 31, 2008	
(Thousands of Dollars)	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation - Liabilities**	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation - Liabilities**
Long term purchased power agreements	$ 335,634	$ 331,659	$ 374,692	$ 353,531
Commodity derivatives	109,625	37,707	52,968	54,307
Interest rate derivatives		17,602		8,503
Total	$ 445,259	$ 386,968	$ 427,660	$ 416,341

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.

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

	Three Months Ended Sept. 30,	
(Thousands of Dollars)	**2009**	**2008**
Accumulated other comprehensive loss related to cash flow hedges at July 1	$ (9,782)	$ (6,134)
After-tax net unrealized losses related to derivatives accounted for as hedges	(6,589)	(2,589)
After-tax net realized losses on derivative transactions reclassified into earnings	1,032	67

Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$	(15,339)	$	(8,656)

	Nine Months Ended Sept. 30,			
(Thousands of Dollars)	**2009**		**2008**	
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$	(13,113)	$	(1,416)
After-tax net unrealized losses related to derivatives accounted for as hedges		(5,770)		(7,347)
After-tax net realized losses on derivative transactions reclassified into earnings		3,544		107
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$	(15,339)	$	(8,656)

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The following table details the fair value of commodity and interest rate derivatives recorded to derivative instruments valuation in the consolidated balance sheet, by category:

	Sept. 30, 2009		
(Thousands of Dollars)	Fair Value	Counterparty Netting (a)	Derivative Instruments Valuation
Current derivative assets			
Other derivative instruments:			
Trading commodity	$ 22,719	$ (14,050)	$ 8,669
Electric commodity	43,924	945	44,869
Natural gas commodity	29,747	1,126	30,873
Total current derivative assets	$ 96,390	$ (11,979)	$ 84,411
Noncurrent derivative assets			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	$ 86	$	$ 86
Other derivative instruments:			
Trading commodity	22,457	(6,351)	16,106
Natural gas commodity	8,872	150	9,022
	31,329	(6,201)	25,128
Total noncurrent derivative assets	$ 31,415	$ (6,201)	$ 25,214
Current derivative liabilities			
Derivatives designated as cash flow hedges:			
Interest rate	$ 2,643	$	$ 2,643
Vehicle fuel and other commodity	4,428		4,428
	7,071		7,071
Other derivative instruments:			
Interest rate	1,522		1,522
Trading commodity	22,572	(18,459)	4,113
Electric commodity	7,696	946	8,642
Natural gas commodity	8,978	1,124	10,102
	40,768	(16,389)	24,379
Total current derivative liabilities	$ 47,839	$ (16,389)	$ 31,450
Noncurrent derivative liabilities			
Derivatives designated as cash flow hedges:			
Interest rate	$ 8,222	$	$ 8,222
Vehicle fuel and other commodity	947		947
	9,169		9,169
Other derivative instruments:			
Interest rate	5,215		5,215
Trading commodity	15,680	(6,355)	9,325
Natural gas commodity		150	150
	20,895	(6,205)	14,690
Total noncurrent derivative liabilities	$ 30,064	$ (6,205)	$ 23,859

(a) *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.

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The following table details the impact of derivative activity during the three and nine months ended Sept. 30, 2009, on other comprehensive income, regulatory assets and liabilities, and income:

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

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

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues.

(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 operating and maintenance expenses.

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At Sept. 30, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 30,395,000 megawatt hours (MwH) of electricity, 86,673,000 MMBtu of natural gas, and 4,375,000 gallons of vehicle fuel. These amounts reflect the gross notional amounts of futures, forwards and financial transmission rights and are not reflective of net positions in the underlying commodities. Notional amounts for options are also included on a gross basis, but are weighted for the probability of exercise.

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 rating. If the credit rating of SPS were downgraded below investment grade, the counterparty to an interest rate swap agreement with SPS would have the ability to terminate the contract, which at Sept. 30, 2009 would have resulted in the payment of the fair value of the derivative liability to the counterparty of approximately $6.7 million. At Sept. 30, 2009, there was no collateral posted on this specific contract.

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. As of Sept. 30, 2009, Xcel Energy s utility subsidiaries had no collateral posted related to adequate assurance clauses in derivative contracts.

11. Financial Instruments

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

	Sept. 30, 2009		Dec. 31, 2008	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Nuclear decommissioning fund	$ 1,234,006	$ 1,234,006	$ 1,075,294	$ 1,075,294
Other investments	11,477	11,477	9,864	9,864
Long-term debt, including current portion	8,129,934	9,045,330	8,290,460	8,562,277

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 Sept. 30, 2009 and Dec. 31, 2008. 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. On Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy had issued guarantees of up to $71.4 million and $67.5 million, respectively, with $17.9 million and $18.2 million of known exposure under these guarantees, respectively. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of Sept. 30, 2009 and Dec. 31, 2008, was approximately $29.9 million and $27.9 million, respectively. 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.

Letters of Credit Xcel Energy and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2009 and Dec. 31, 2008, there were $22.1 million and $24.1 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.

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12. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted new guidance for recurring fair value measurements contained in *ASC 820 Fair Value Measurements and Disclosures* which 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 was established by this guidance. The three levels in the hierarchy and examples of each level are as follows:

Level 1 Quoted prices are available in active markets for identical assets 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, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

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, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights (FTRs).

The following tables present, for each of these hierarchy levels, Xcel Energy s assets and liabilities that are measured at fair value on a recurring basis:

			Sept. 30, 2009		
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Counterparty Netting**	**Net Balance**
Assets					
Nuclear decommissioning fund					
Cash equivalents	$	$ 16,386	$	$	$ 16,386
Debt securities		569,303	98,233		667,536
Equity securities	550,084				550,084
Commodity derivatives		63,768	64,037	(18,180)	109,625
Total	**$** 550,084	**$** 649,457	**$** 162,270	$ (18,180)	**$** 1,343,631
Liabilities					
Commodity derivatives	$	$ 40,585	$ 19,716	$ (22,594)	$ 37,707
Interest rate derivatives		17,602			17,602
Total	$	$ 58,187	$ 19,716	$ (22,594)	$ 55,309

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	Dec. 31, 2008				
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Counterparty Netting**	**Net Balance**
Assets					
Cash equivalents	$	$ 50,000	$	$	$ 50,000
Nuclear decommissioning fund					
Cash equivalents		8,449			8,449
Debt securities		491,486	109,423		600,909
Equity securities	465,936				465,936
Commodity derivatives		29,648	39,565	(16,245)	52,968
Total	**$** 465,936	**$** 579,583	**$** 148,988	**$** (16,245)	**$** 1,178,262
Liabilities					
Commodity derivatives	$ 600	$ 78,714	$ 16,344	$ (41,351)	$ 54,307
Interest rate derivatives		8,503			8,503
Total	$ 600	$ 87,217	$ 16,344	$ (41,351)	$ 62,810

The following tables present the changes in Level 3 recurring fair value measurements for the three and nine months ended Sept. 30, 2009 and 2008:

	Three Months Ended Sept. 30,			
	2009		2008	
(Thousands of Dollars)	**Commodity Derivatives, Net**	**Nuclear Decommissioning Fund**	**Commodity Derivatives, Net**	**Nuclear Decommissioning Fund**
Balance July 1	$ 49,311	$ 86,337	$ 24,149	$ 109,416
Purchases, issuances, and settlements, net	(1,557)	5,790	(2,960)	9,110
Transfers into (out of) Level 3	1,202		(1,466)	
Losses recognized in earnings	1,197		2,382	
Gains (losses) recognized as regulatory assets and liabilities	(5,832)	6,106	5,758	(4,572)
Balance Sept. 30	$ 44,321	$ 98,233	$ 27,863	$ 113,954

	Nine Months Ended Sept. 30,			
	2009		2008	
(Thousands of Dollars)	**Commodity Derivatives, Net**	**Nuclear Decommissioning Fund**	**Commodity Derivatives, Net**	**Nuclear Decommissioning Fund**
Balance Jan. 1	$ 23,221	$ 109,423	$ 19,466	$ 108,656
Purchases, issuances, and settlements, net	(2,779)	(22,335)	(10,031)	12,760
Transfers into (out of) Level 3	1,770		(1,414)	
Gains recognized in earnings	(878)		(3,884)	
Gains (losses) recognized as regulatory assets and liabilities	22,987	11,145	23,726	(7,462)
Balance Sept. 30	$ 44,321	$ 98,233	$ 27,863	$ 113,954

Gains on Level 3 commodity derivatives recognized in earnings for the three months ended Sept. 30, 2009, include $2.3 million of net unrealized gains relating to commodity derivatives held at Sept. 30, 2009. Losses on Level 3 commodity derivatives recognized in earnings for the nine months ended Sept. 30, 2009, included $6.7 million of net unrealized gains relating to commodity derivatives held at Sept. 30, 2009. Gains and losses on Level 3 commodity derivatives recognized in earnings for the three and nine months ended Sept. 30, 2008, include $1.2 million and $4.7 million of net unrealized gains relating to commodity derivatives held at Sept. 30, 2008. 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 other comprehensive income or deferred as regulatory assets and liabilities. The classification as a regulatory asset or liability is based on the commission approved regulatory recovery mechanisms. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

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13. Other Income (Expense), Net

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

(Thousands of Dollars)	Three Months Ended Sept. 30, 2009	2008	Nine Months Ended Sept. 30, 2009	2008
Interest income	$ 2,709	$ 9,854	$ 8,775	$ 22,244
Other nonoperating income	248	1,146	3,078	4,752
Insurance policy (expenses) income	(3,534)	(1,264)	(6,877)	274
Other nonoperating expenses	(400)		(582)	
Other income (expense), net	$ (977)	$ 9,736	$ 4,394	$ 27,270

14. 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.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2009					
Operating revenues from external customers	$ 2,128,955	$ 169,601	$ 16,006	$	$ 2,314,562
Intersegment revenues	151	584		(735)	
Total revenues	$ 2,129,106	$ 170,185	$ 16,006	$ (735)	$ 2,314,562
Income (loss) from continuing operations	$ 235,751	$ (1,000)	$ 152	$ (13,110)	$ 221,793
Three Months Ended Sept. 30, 2008					
Operating revenues from external customers	$ 2,576,467	$ 258,961	$ 16,252	$	$ 2,851,680
Intersegment revenues	225	1,208		(1,433)	
Total revenues	$ 2,576,692	$ 260,169	$ 16,252	$ (1,433)	$ 2,851,680
Income (loss) from continuing operations	$ 223,464	$ 3,960	$ 7,817	$ (12,546)	$ 222,695

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2009					
Operating revenues from external customers	$ 5,749,207	$ 1,224,161	$ 52,819	$	$ 7,026,187
Intersegment revenues	569	2,505		(3,074)	
Total revenues	$ 5,749,776	$ 1,226,666	$ 52,819	$ (3,074)	$ 7,026,187
Income (loss) from continuing operations	$ 473,392	$ 71,070	$ 14,739	$ (44,526)	$ 514,675
Nine Months Ended Sept. 30, 2008					
Operating revenues from external customers	$ 6,704,164	$ 1,736,701	$ 54,718	$	$ 8,495,583
Intersegment revenues	767	5,831		(6,598)	
Total revenues	$ 6,704,931	$ 1,742,532	$ 54,718	$ (6,598)	$ 8,495,583

Income (loss) from continuing operations	$	423,310	$	83,398	$	23,423	$	(47,969)	$	482,162

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15. 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 Sept. 30, 2009 and 2008, Xcel Energy had approximately 7.3 million and 8.0 million stock options outstanding, respectively, that were antidilutive and excluded from the earnings per share calculation. For the nine months ended Sept. 30, 2009 and 2008, Xcel Energy had approximately 7.7 million and 8.0 million stock options outstanding, respectively, that were antidilutive and excluded from the earnings per share calculation.

The dilutive impact of common stock equivalents affected earnings per share as follows for the three and nine months ended Sept. 30, 2009 and 2008:

	Three Months Ended Sept. 30, 2009			Three Months Ended Sept. 30, 2008		
(Amounts in thousands, except per share data)	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**
Net income	$ 220,828			$ 222,789		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	219,768	456,769	$ 0.48	221,729	434,131	$ 0.51
Effect of dilutive securities:						
Convertible senior notes				801	4,663	
401(k) equity awards		683			583	
Stock options		1			20	
Diluted earnings per share:						
Earnings available to common shareholders and assumed conversions	$ 219,768	457,453	$ 0.48	$ 222,530	439,397	$ 0.51

	Nine Months Ended Sept. 30, 2009			Nine Months Ended Sept. 30, 2008		
(Amounts in thousands, except per share data)	**Income**	**Shares**	**Per Share Amount**	**Income**	**Shares**	**Per Share Amount**
Net income	$ 512,002			$ 481,478		
Less: Dividend requirements on preferred stock	(3,180)			(3,180)		
Basic earnings per share:						
Earnings available to common shareholders	508,822	456,095	$ 1.12	478,298	431,511	$ 1.11
Effect of dilutive securities:						
Convertible senior notes				2,382	4,663	
401(k) equity awards		634			516	
Stock options					26	
Diluted earnings per share:						
Earnings available to common shareholders and assumed conversions	$ 508,822	456,729	$ 1.11	$ 480,680	436,716	$ 1.10

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16. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended Sept. 30,			
	2009	2008	2009	2008
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 16,365	$ 15,851	$ 1,166	$ 1,338
Interest cost	42,448	42,630	12,603	12,720
Expected return on plan assets	(64,135)	(68,584)	(5,694)	(7,963)
Amortization of transition obligation			3,611	3,644
Amortization of prior service cost (credit)	6,155	5,166	(681)	(544)
Amortization of net loss	3,114	3,185	4,832	2,875
Net periodic benefit cost (credit)	3,947	(1,752)	15,837	12,070
(Cost) credits not recognized and additional cost recognized due to the effects of regulation	(723)	2,258	972	972
Net benefit cost recognized for financial reporting	$ 3,224	$ 506	$ 16,809	$ 13,042

	Nine Months Ended Sept. 30,			
	2009	2008	2009	2008
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 49,095	$ 47,553	$ 3,499	$ 4,013
Interest cost	127,343	127,890	37,809	38,160
Expected return on plan assets	(192,404)	(205,753)	(17,082)	(23,888)
Amortization of transition obligation			10,833	10,932
Amortization of prior service cost (credit)	18,464	15,498	(2,044)	(1,632)
Amortization of net loss	9,342	9,555	14,497	8,624
Net periodic benefit cost (credit)	11,840	(5,257)	47,512	36,209
(Cost) credits not recognized and additional cost recognized due to the effects of regulation	(2,169)	6,775	2,918	2,918
Net benefit cost recognized for financial reporting	$ 9,671	$ 1,518	$ 50,430	$ 39,127

During 2009, voluntary contributions were made by Xcel Energy to the New Century Energies Inc. Retirement Plan for PSCo Bargaining Unit Employees and Former Non Bargaining Unit Employees (PSCo Bargaining Plan) of $1.5 million and to the Xcel Energy Inc. Non Bargaining Pension Plan (South) of $0.5 million. In addition, voluntary contributions were made by PSCo to the PSCo Bargaining Plan of $71.6 million and to the Xcel Energy Inc. Non Bargaining Pension Plan (South) of $18.3 million, and by SPS to the Xcel Energy Inc. Non Bargaining Pension Plan (South) of $8.0 million.

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 the 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, 2008, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2009.

RESULTS OF OPERATIONS

Earnings per Share Summary

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

Diluted earnings (loss) per share	Three Months Ended Sept. 30, 2009		Three Months Ended Sept. 30, 2008		Nine Months Ended Sept. 30, 2009		Nine Months Ended Sept. 30, 2008
PSCo	$	0.20	$	0.20 $	0.51	$	0.56
NSP-Minnesota		0.20		0.25	0.48		0.51
NSP-Wisconsin		0.03		0.03	0.08		0.07
SPS		0.08		0.05	0.14		0.06
Equity earnings of unconsolidated subsidiaries (WYCO)		0.01		0.01	0.02		0.01
Regulated utility continuing operations		0.52		0.54	1.23		1.21
Holding company and other costs		(0.04)		(0.03)	(0.11)		(0.11)
Ongoing(a) diluted earnings per share		**0.48**		**0.51**	**1.12**		**1.10**
PSRI					(0.01)		
GAAP diluted earnings per share	$	**0.48**	$	**0.51** $	**1.11**	$	**1.10**

(a) Ongoing earnings excludes the impact related to the COLI program. During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. The 2009 and 2008 earnings were not materially affected by the termination of the COLI program and the 2009 impact is primarily related to legal costs associated with company claims against the insurance provider and broker of the COLI policies.

PSCo Earnings at PSCo were flat for the third quarter and decreased by five cents per share for the nine months ending Sept. 30, 2009, largely due to the negative impact of weather and rising costs. The decrease was partially offset by new electric rates that went into effect in July 2009. In May 2009, the CPUC approved an annual electric rate increase of $112 million.

NSP-Minnesota Earnings at NSP-Minnesota decreased by five cents per share for the third quarter and by three cents per share for the nine months ending Sept. 30, 2009. The decrease is mainly due to the negative impact of weather, an increase in the effective tax rate and timing of nuclear outage expenses. The decrease was partially offset by an electric rate increase that went into effect in January 2009.

NSP-Wisconsin Earnings at NSP-Wisconsin were flat for the third quarter and increased by one cent per share for the nine months ending Sept. 30, 2009, largely due to improved fuel recovery and new rates which were effective in January 2009.

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SPS Earnings at SPS increased by three cents per share for the third quarter and by eight cents per share for the nine months ending Sept. 30, 2009. The increase was primarily due to electric rate increases in Texas (effective in February 2009) and New Mexico (effective in July 2009) and the 2008 resolution of certain fuel cost allocation issues, which were partially offset by higher purchased capacity costs.

WYCO Equity earnings of unconsolidated subsidiaries were flat for the third quarter and increased by one cent per share for the nine months ending Sept. 30, 2009, due to our investment in WYCO, which owns a natural gas pipeline in Colorado that began operations in late 2008, as well as a storage facility that commenced operations in July 2009.

Holding Company and Other Costs

Financing Costs and Preferred Dividends Holding company and other results include interest expense and the earnings per share impact of preferred dividends, which are incurred at the Xcel Energy and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

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

Contribution to Earnings (Millions of Dollars)	Three Months Ended Sept. 30, 2009	2008	Nine Months Ended Sept. 30, 2009	2008
GAAP income (loss) by segment				
Regulated electric income continuing operations	$ 235.8	$ 223.4	$ 473.4	$ 423.3
Regulated natural gas income continuing operations	(1.0)	4.0	71.1	83.4
Other regulated income(a)	4.2	7.3	17.9	23.3
Segment income continuing operations	239.0	234.7	562.4	530.0
Holding company costs and other results(a)	(17.2)	(12.0)	(47.7)	(47.8)
Total income continuing operations	221.8	222.7	514.7	482.2
Discontinued operations	(1.0)	0.1	(2.7)	(0.7)
Total GAAP net income	$ 220.8	$ 222.8	$ 512.0	$ 481.5

	Three Months Ended Sept. 30, 2009	2008	Nine Months Ended Sept. 30, 2009	2008
GAAP earnings (loss) by segment				
Regulated electric continuing operations	$ 0.50	$ 0.51	$ 1.04	$ 0.97
Regulated natural gas continuing operations		0.01	0.15	0.19
Other regulated income(a)	0.02	0.02	0.04	0.05
Segment earnings per share continuing operations	0.52	0.54	1.23	1.21
Holding company costs and other results(a)	(0.04)	(0.03)	(0.11)	(0.11)
Total earnings per share continuing operations	0.48	0.51	1.12	1.10
Discontinued operations			(0.01)	

Total earnings per share continuing operations	$ 0.48	$ 0.51	$ 1.11	$ 1.10

(a) Not a reportable segment. Refer to Segment Information in Note 14 to the Consolidated Financial Statements.

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The following table summarizes significant components contributing to the changes in the 2009 diluted earnings per share compared with the same periods in 2008, which are discussed in more detail later.

	Three Months Ended Sept. 30,	Nine Months Ended Sept. 30,
2008 GAAP and ongoing(a) diluted earnings per share	**$ 0.51**	**$ 1.10**
Components of change 2009 vs. 2008		
Higher electric margins	0.12	0.30
Lower depreciation and amortization expenses	0.02	0.02
Higher allowance for funds used during construction equity	0.01	0.02
Higher operating and maintenance expenses	(0.06)	(0.10)
Higher conservation and DSM expenses (generally offset in revenues)	(0.03)	(0.06)
Lower other income (expense), net	(0.02)	(0.03)
Dilution from DRIP, benefit plan and the 2008 common equity issuance	(0.02)	(0.05)
Higher taxes, other than income taxes	(0.01)	(0.02)
Lower natural gas margins	(0.01)	(0.03)
Higher interest expenses		(0.02)
Other, including higher effective tax rate	(0.03)	(0.01)
2009 GAAP diluted earnings per share	**0.48**	**1.12**
PSRI		(0.01)
2009 ongoing(a) diluted earnings per share	**$ 0.48**	**$ 1.11**

(a) Ongoing earnings excludes the impact related to the COLI program. During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. The 2009 and 2008 earnings were not materially affected by the termination of the COLI program and the 2009 impact is primarily related to legal costs associated with company claims against the insurance provider and broker of the COLI policies.

Utility Results

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

	Three Months Ended Sept. 30,			Nine Months Ended Sept. 30,		
	2009 vs. Normal	2008 vs. Normal	2009 vs. 2008	2009 vs. Normal	2008 vs. Normal	2009 vs. 2008
Retail electric	$ (0.05)	$ (0.01)	$ (0.04)	$ (0.05)	$ (0.01)	$ (0.04)
Firm natural gas				(0.01)	0.01	(0.02)
Total	$ (0.05)	$ (0.01)	$ (0.04)	$ (0.06)	$	$ (0.06)

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 Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	**2009**	**2008**	**2009**	**2008**
Electric revenues	$ 2,129	$ 2,576	$ 5,749	$ 6,704
Electric fuel and purchased power	(982)	(1,514)	(2,704)	(3,871)
Electric margin	$ 1,147	$ 1,062	$ 3,045	$ 2,833

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

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2009 vs. 2008	Nine Months Ended Sept. 30, 2009 vs. 2008
Fuel and purchased power cost recovery	$ (518)	$ (1,143)
Estimated impact of weather	(26)	(24)
NSP-Minnesota rate case provision for refund (largely offset in depreciation expense)	(25)	(30)
Trading	(11)	(63)
Sales mix and demand revenues	(5)	10
Retail rate increases (Colorado, Minnesota, Texas, New Mexico and Wisconsin)	98	190
Conservation and DSM revenues (generally offset by expenses)	20	53
2008 refund of nuclear refueling outage revenues due to change in recovery method	14	15
Non-fuel riders	4	18
MERP rider	3	13
Transmission revenue	3	9
Retail sales decline (excluding weather impact)		(17)
SPS 2008 fuel cost allocation regulatory accruals		12
Other, net	(4)	2
Total decrease in electric revenue	$ (447)	$ (955)

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2009 vs. 2008	Nine Months Ended Sept. 30, 2009 vs. 2008
Retail rate increases (Colorado, Minnesota, Texas, New Mexico and Wisconsin)	$ 98	$ 190
Conservation and DSM revenues (generally offset by expenses)	20	53
2008 refund of nuclear refueling outage revenues due to change in recovery method	14	15
Non-fuel riders	4	18
MERP rider	3	13
NSP-Wisconsin fuel recovery	3	10
Firm wholesale	2	10
Estimated impact of weather	(26)	(24)
NSP-Minnesota rate case provision for refund (largely offset in depreciation expense)	(25)	(30)
Purchased capacity costs	(11)	(44)
Sales mix and demand revenues	(5)	10
Retail sales (decline excluding weather impact)		(17)
SPS 2008 fuel cost allocation regulatory accruals		12
Other, net	8	(4)
Total increase in electric margin	$ 85	$ 212

Xcel Energy has experienced a decline in MwH sales, which we believe is driven by overall economic conditions, and to a lesser degree, increased conservation efforts. Our most significant declines have occurred in commercial and industrial sales, which are directly related to the economic downturn. The declines in MwH sales to the commercial and industrial customer class are partially offset by demand fees, which mitigate to a certain degree the impact of the lower MwH sales.

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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 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 Sept. 30, 2009	Three Months Ended Sept. 30, 2008	Nine Months Ended Sept. 30, 2009	Nine Months Ended Sept. 30, 2008
Natural gas revenues	$ 170	$ 259	$ 1,224	$ 1,737
Cost of natural gas sold and transported	(72)	(156)	(810)	(1,299)
Natural gas margin	$ 98	$ 103	$ 414	$ 438

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2009 vs. 2008	Nine Months Ended Sept. 30, 2009 vs. 2008
Purchased natural gas adjustment clause recovery	$ (85)	$ (493)
Sales mix	(2)	(4)
Transportation margin	(2)	(1)
Conservation and DSM revenues (generally offset by expenses)	1	2
Estimated impact of weather		(13)
Other, net	(1)	(4)
Total decrease in natural gas revenues	$ (89)	$ (513)

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2009 vs. 2008	Nine Months Ended Sept. 30, 2009 vs. 2008
Sales mix	$ (2)	$ (4)
Transportation margin	(2)	(2)
Estimated impact of weather	(1)	(13)
Conservation and DSM revenues (generally offset by expenses)	1	2
Other, net	(1)	(7)
Total decrease in natural gas margin	$ (5)	$ (24)

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Non-Fuel Operating Expense and Other Items

Other Operating and Maintenance (O&M) Expenses O&M expenses increased by approximately $43.9 million, or 10.4 percent, for the third quarter and approximately $70.4 million, or 5.3 percent for the first nine months of 2009, compared with 2008. The following table summarizes the changes in other O&M expenses:

(Millions of Dollars)	Three Months Ended Sept. 30, 2009 vs. 2008	Nine Months Ended Sept. 30, 2009 vs. 2008
Nuclear outage costs, net of deferral	$ 27	$ 26
Higher employee benefit costs	15	40
Higher nuclear plant operation costs	4	20
Higher plant generation costs	3	5
Lower consulting costs	(7)	(19)
Other, net	2	(2)
Total increase in other operating and maintenance expenses	$ 44	$ 70

- The increase in nuclear outage costs is due to the timing of outages in conjunction with the commissions approval of the change in the nuclear refueling outage recovery method from the direct expense method to the deferral and amortization method in the third quarter of 2008.

- Higher employee benefits costs are primarily attributable to increased pension costs, in part, related to market losses on retirement benefit plan assets, as well as higher employee medical plan costs.

- The increase in nuclear plant operation costs is driven primarily by an increase in security costs and regulatory fees, resulting from new Nuclear Regulatory Commission requirements.

- Lower consulting costs are primarily the result of cost management initiatives implemented in early 2009.

Conservation and DSM Program Expenses Conservation and DSM program expenses increased approximately $19.7 million for the third quarter of 2009, and by $41.5 million for the first nine months of 2009, compared with the same periods in 2008. The higher expense is attributable to the expansion of programs and regulatory commitments. Conservation and DSM program expenses are generally recovered through riders in our major jurisdictions or through base rates with tracker mechanisms.

Depreciation and Amortization Depreciation and amortization expenses decreased by approximately $10.9 million, or 5.2 percent, for the third quarter of 2009, and by $13.2 million, or 2.1 percent, for the first nine months of 2009, compared with the same periods in 2008. In September 2009, as a result of the MPUC decision, in the Minnesota electric rate case, NSP-Minnesota began recognizing a 10-year life extension of the Prairie Island nuclear plant for purposes of determining depreciation, effective Jan. 1, 2009. In addition, in June 2009, the MPUC extended the recovery period of decommissioning expense by 10 years for the Prairie Island and the Monticello nuclear plants. These decreases were partially offset by normal system expansion.

Taxes (Other Than Income Taxes) Taxes (other than income taxes) increased by approximately $8.7 million, or 12.3 percent, for the third quarter of 2009, and by $10.8 million, or 5.0 percent, for the first nine months of 2009, compared with the same periods in 2008. The increase is primarily due to increased property taxes.

Other Income (Expense), Net Other income (expense), net, decreased $10.7 million during the third quarter of 2009 and $22.9 million for the first nine months of 2009, compared with the same periods in 2008. The net decline is mainly due to changes in our non-qualified benefit plan liabilities related to market activity, lower interest on under recovered deferred fuel balances and a decrease in interest received from WYCO for construction deposits.

Allowance for Funds Used During Construction, Equity and Debt (AFDC) AFDC increased by approximately $2.3 million, or 8.8 percent, for the third quarter of 2009, and by $11.0 million, or 14.8 percent, for the first nine months of 2009, compared with the same periods in 2008. The increase was due primarily to the construction of Comanche Unit 3, a power facility located in Colorado which is expected to be completed in the fourth quarter of 2009, as well as other construction projects.

Interest Charges Interest charges decreased by approximately $0.4 million, or 0.3 percent, for the third quarter of 2009 and increased by $14.8 million, or 3.6 percent, for the first nine months of 2009, compared with the same periods in 2008. The lower interest expense in the third quarter was largely due to a maturing bond at NSP-Minnesota that was repaid by issuing lower-cost short-term debt. This short-term debt is expected to be refinanced with long-term debt later in the year. The year-to-date increase was primarily the result of increased debt levels to fund new capital investments.

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Income Taxes Income tax expense for continuing operations increased by $14.1 million for the third quarter of 2009, compared with 2008. The effective tax rate for continuing operations was 38.4 percent for the third quarter of 2009, compared with 35.3 percent for the same period in 2008. Income tax expense for continuing operations increased by $27.8 million for the first nine months of 2009, compared with the first nine months of 2008. The effective tax rate for continuing operations was 35.8 percent for the first nine months of 2009, compared with 34.4 percent for the same period in 2008.

The higher effective tax rates were primarily due to the recognition of additional state unitary tax expense and the establishment of a valuation allowance against certain state tax credit carryovers that are now expected to expire, which was partially offset by wind energy production tax credits. Excluding these expense items, the effective tax rate for the third quarter and first nine months of 2009 would have been 36.4 percent and 34.8 percent, respectively. We expect the effective tax rate for 2009 continuing operations to be approximately 34 percent to 36 percent.

Equity Earnings of Unconsolidated Subsidiaries Equity earnings of unconsolidated subsidiaries increased by $4.0 million for the third quarter of 2009, and by $9.6 million, for the first nine months of 2009, compared with the same periods in 2008. The increase is primarily due to higher earnings from the equity investment in WYCO as a result of the High Plains natural gas pipeline, located in Colorado, commencing operations in late 2008, as well as a storage facility that commenced operations in July 2009.

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, 2008.

Public Utility Regulation

NSP-Minnesota

Minnesota Resource Plan In 2007, NSP-Minnesota filed its resource plan, which covers 2008-2022. The plan would reduce CO_2 emissions by 22 percent from 2005 by 2020, a 6 million ton reduction.

In July 2009, the MPUC approved NSP-Minnesota s 2007 resource plan, including the following components:

- Energy efficiency savings of 1.15 percent in 2010, 1.2 percent in 2011 and 1.3 percent in 2012;
- Install sufficient renewables to meet the Minnesota RES;
- Obtain required approvals to extend the life of the Prairie Island nuclear plant and to increase the output at both Prairie Island and Monticello;
- Continue ongoing capacity expansion at Sherco Unit 3;
- Continue to investigate repowering Black Dog Units 3 and 4, and provide the MPUC with specific plans and timelines for the repowering;
- Obtain approval for the 375 MW intermediate and 350 MW diversity exchange with Manitoba Hydro beginning in 2015; and
- Continue to ensure sufficient transmission available to deliver generation to load.

Additionally, the MPUC required NSP-Minnesota to consider higher levels of DSM and energy efficiency and provide recommendations in NSP-Minnesota s next resource plan, which is to be filed no later than Aug. 1, 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. Excelsior filed this petition making claims pursuant to Minnesota statutes relating to an Innovative Energy Project and Clean Energy Technology. NSP-Minnesota opposed the petition.

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.

The MPUC issued its order for Phase 1 of the hearing on Aug. 30, 2007. In it, the MPUC found among other things, that Excelsior and NSP-Minnesota should resume negotiations toward an acceptable purchase power agreement, with assistance from the Minnesota Department of Commerce (MDOC) and the guidance provided by the order.

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On Sept. 24, 2008, the MPUC denied Excelsior Energy s Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW IGCC generating facility. On May 28, 2009, the MPUC affirmed its September 2008 order and *denied Excelsior Energy s motion, which closes the docket*. A written order was issued July 7, 2009. On Aug. 6, 2009, Excelsior appealed the MPUC decision to the Minnesota Court of Appeals. Briefings are expected to be completed in November 2009, with oral arguments scheduled subsequently.

Prairie Island Certificate of Need (CON) On May 16, 2008, NSP-Minnesota filed for a CON for life extension and a separate request for approval of an enhanced power uprate at both Prairie Island Units 1 and 2. The City of Red Wing, Minn. and the Prairie Island Indian Community (PIIC) filed testimony raising concerns about the cost to the community and certain health and safety concerns. The OES filed testimony supporting the uprates. Evidentiary hearings were held in June 2009. The ALJ recommended granting the requested CONs in his report issued Oct. 21, 2009. Pursuant to a 2003 law, if the MPUC grants a CON request for additional dry cask storage, it is stayed for one legislative session. NSP-Minnesota also filed for a license extension with the NRC on April 15, 2008. The PIIC intervened in the proceeding and raised seven points of contention. As of July 15, 2009, NSP-Minnesota and the PIIC have resolved six of these contentions. The final environmental impact statement was published in the state proceeding July 31, 2009. At this time, it is uncertain when ultimate approval of the license extension will occur.

Wind Generation NSP-Minnesota plans to invest approximately $900 million over three years for a 201 MW project in southwestern Minnesota, called the Nobles Wind Project, and a 150 MW project in southeastern North Dakota, called the Merricourt Wind Project. These projects are expected to be operational by the end of 2010 and 2011, respectively. In June 2009, the MPUC issued an order approving investments in the Nobles and Merricourt Wind Projects. In August 2009, the NDPSC granted advanced determinations of prudence to the Nobles and Merricourt Wind Projects and a certificate of public convenience and necessity (CPCN) to the Merricourt project. In October 2009, the NDPSC voted to obtain additional information to determine whether or not to reopen the Merricourt Wind Project CPCN as a result of the impact on other North Dakota utilities and their retail customers of the MISO cost allocation applicable to transmission investments associated with the Merricourt project. On Oct. 23, 2009, the FERC approved a modified MISO cost allocation method that is expected to reduce the impact on other North Dakota utilities and their customers.

NSP-Minnesota Transmission CONs In August 2007, NSP-Minnesota and Great River Energy (on behalf of eight other regional transmission providers) filed a CON application, for three 345 kilovolt (KV) 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 cost of the project 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.

In April 2009, the MPUC granted a CON to construct three 345 KV electric transmission lines in Minnesota. The MPUC also included a condition regarding 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.

As part of CapX 2020, NSP-Minnesota and Great River Energy have filed two route permit applications with the MPUC. In December 2008, the route permit application for the Brookings to Hampton Corner Project was filed. In April 2009, the route permit application for the Monticello to St. Cloud portion of the Fargo Twin Cities project was filed. In October 2009, the route permit application for the St. Cloud to Fargo project was filed with the MPUC. Route permit applications for the remaining parts of the three projects are expected to be filed in Minnesota later this year. Permit filings are expected to be made in adjoining states. NSP-Minnesota anticipates the first routing decisions in early 2010.

As part of CapX 2020, Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative (on behalf of themselves and NSP-Minnesota and Great River Energy) filed a CON application in March 2008 for a 230 KV transmission line between Bemidji and Grand Rapids, Minn. A route application for this project was filed in June 2008. The need application is uncontested; route hearings are expected to be conducted in late 2009, and an MPUC decision is anticipated by the second 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 to be completed by end of 2011. The estimated cost to NSP-Minnesota is approximately $26 million.

NSP-Wisconsin

Bay Front Biomass Gasification In February 2009, NSP-Wisconsin filed an application with the PSCW for a certificate of authority (CA) to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wis. Currently, two of the three boilers at Bay Front use biomass as their primary fuel to generate electricity. The proposed project will convert the third boiler to biomass gasification technology allowing the plant to use 100 percent biomass in all three boilers. The project, estimated to cost $58 million, will require 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. The total generation output of the plant is not expected

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to change significantly as a result of the project. However, the project will improve the environmental performance of the plant and contribute towards state RES in the region. Following all state regulatory approvals, engineering and design work is expected to begin in 2010, and the unit could be operational by late 2012. Intervenors have filed testimony both supporting and opposing the project. The request is pending a decision by the PSCW.

NSP-Minnesota also made filings in North Dakota and Minnesota to help ensure future rate recovery of the portion of the project costs that will be billed to NSP-Minnesota through the Interchange Agreement. Decisions on those filings are currently pending regulatory action before the NDPSC and the MPUC respectively.

PSCo

PSCo Resource Plan In November 2007, PSCo filed the Colorado Resource Plan, which details the type and amount of resources that will be added to the system for an eight year resource acquisition period through 2015. The CPUC issued its order in September 2008, which approved the following:

- Increase in wind portfolio of 850 MW by 2015. PSCo would then have a total of approximately 1,900 MW of wind power resources;
- Approximately 200 MW from a central solar thermal facility with storage, with possible option of acquiring up to 600 MW of solar thermal resources with storage as technology develops;
- Increase customer efficiency and conservation programs with plans to meet the CPUC goals of annual energy sales reductions to approximately 3,669 gigawatt hours, that would yield a demand savings in the range of 886 MW to 994 MW by 2020;
- Retirement of two older coal-burning plants (two units at Arapahoe and two units at Cameo), replacing the capacity with company owned resources, provided the costs are reasonable; and
- Reduce PSCo s CO_2 emissions by 10 percent below 2005 levels and for PSCo to propose additional reductions to achieve a 20 percent reduction by 2020 in its next plan.

PSCo acquired 174 MW of wind resources and 19 MW of central station photovoltaic (PV) through separate requests for proposal and those contracts were specifically approved by the CPUC. In January 2009, PSCo issued an all-source request for proposals to fill the approved resource plan. Bids were received in April 2009, and PSCo filed its bid evaluation report (120-day all-source report) with the CPUC in August 2009.

In October 2009, the CPUC approved the acquisitions of the resources identified in the 120 day all-source report. With minor modification, the CPUC adopted PSCo s preferred plan which includes an incremental 900 MW of additional intermittent renewable energy resources (wind and 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 designate certain bidders. The CPUC approved the selection of about 800 MW of traditional gas-fired resources. The CPUC preferred to follow the normal course of business whereby PSCo would file its next resource plan in the fall of 2011 rather than making an interim filing in 2010. A final order is due out early November 2009.

San Luis Valley-Calumet-Comanche Transmission Project **PSCo and Tri-State Generation and Transmission Association filed a joint application for a certificate of need and public convenience (CPCN) in May 2009. The project consists of four components of both 230 KV and 345 KV line and substation construction. The line is intended to assist in bringing solar power in the San Luis Valley to load. The line is expected to be placed in-service in 2013 if no significant issues in the siting and permitting of the line are encountered. Several landowners are opposing this transmission line, including two large ranches. Opposing testimony is scheduled to be filed on Oct. 28, 2009. Hearings are scheduled for mid-December 2009, with a final order to issue in February 2010.**

SPS

SPS Participation in the SPP RTO In October 2007, as part of the resolution of the 2007 SPS New Mexico retail rate case, the NMPRC ordered an investigation of the benefits of SPS participation in the SPP RTO. In June 2009, the NMPRC expanded the scope of the docket to include the issue of placing SPS retail loads in New Mexico under Network Integration Transmission Service (NITS) under the SPP OATT effective Jan. 1, 2010. The conversion to service under the SPP Tariff is mandatory for SPS by Feb. 1, 2010 under the SPP membership agreement. In September 2009, the parties filed a stipulation resolving all issues in the proceeding for a five year interim period, subject to certain reporting by SPS. A hearing on the stipulation is scheduled for Nov. 17, 2009 before the NMPRC hearing examiner.

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

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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, 2008. In addition to the matters discussed below, see Note 6 to the consolidated financial statements for a discussion of other regulatory matters.

Electric Reliability Standards Compliance

Compliance Audits

The NSP System and PSCo were subject to electric reliability standards compliance audits in the first and second quarters of 2008, respectively. The Midwest Reliability Organization (MRO) found the NSP System in compliance with all NERC standards audited. On Oct. 31, 2008, the Western Electricity Coordinating Council (WECC) auditors issued their final audit report. The report found a possible violation of one standard related to relay maintenance.

In 2008, the NSP System, PSCo and SPS filed self-reports with the MRO, WECC and SPP, respectively, relating to failure to complete certain generation station battery tests, relay maintenance intervals and certain critical infrastructure protection standards. In August and September of 2009, the NSP System, PSCo, and SPS each reached agreement with the relevant regional entity that would resolve all open audit findings and self reports by payment of a non-material penalty. Xcel Energy is in the process of developing definitive settlement agreements with each of the regions. These settlement agreements will be subject to NERC and FERC approval.

NERC Compliance Investigation

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, as a result of a series of transmission line outages. The initial transmission line outages appear to have 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. The final outcome of the NERC compliance investigation is unknown at this time. Given the ongoing investigation, Xcel Energy is unable to determine if the outcome of this matter will result in any finding of standards violations, and if so whether any associated penalties will have a material adverse impact on operations, cash flows or financial condition.

MISO Generation Interconnection Cost Allocation Tariff In July 2009, MISO and its transmission owners (including NSP-Minnesota and NSP-Wisconsin) filed to change the cost allocation procedures in the MISO tariff associated with interconnection of new generation. The current rule requires the interconnecting generator to fund 50 percent of the network upgrades associated with the interconnection, with 50 percent funded by the affected transmission owners. The proposed change would require the interconnecting generator to fund 90 or 100 percent of the costs (based on the size of the facility) on an interim basis until MISO and its stakeholders can develop a replacement tariff in 2010. Approximately 40 parties, including Xcel Energy, filed interventions or protests with extensive objections filed by several wind generation developers. Xcel Energy urged the FERC to require MISO and its stakeholders to develop and file a replacement tariff by April 1, 2010, so the tariff could be in effect by July 2010. Xcel Energy indicated uncertainly regarding cost allocation and cost recovery could affect pending transmission projects. On Oct. 23, 2009, FERC approved the modified tariff effective July 9, 2009, conditioned on MISO filing a revised tariff by July 2010. FERC also ruled the interim tariff will be applicable to all generation interconnection agreements executed or filed with FERC during the period July 9, 2009 to July 2010.

FERC Audit of Wholesale FCA In October 2009, the FERC notified NSP-Minnesota and NSP-Wisconsin that the FERC audit division began an audit of compliance with the FERC s accounting and reporting regulations related to the calculation of the NSP-Minnesota and NSP-Wisconsin wholesale FCA for the period commencing Jan. 1, 2008. The audit is a periodic financial audit and does not imply any non-compliance has occurred.

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

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments

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regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which all may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, 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, 2008, includes a discussion of accounting policies 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.

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 in its Annual Report on Form 10-K for the year ended Dec. 31, 2008. 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, the continued turmoil in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Continued distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning trust fund and master pension trust, as well as Xcel Energy s ability to earn a return on short-term investments of excess cash.

Commodity Price Risk Xcel Energy 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.

At Sept. 30, 2009, a 10 percent increase in prices would have resulted in a net increase in commodity derivative assets of $44.8 million, while a decrease of 10 percent would have resulted in a commodity derivative assets increase of $21.0 million.

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.

The fair value of the commodity trading contracts were as follows:

(Thousands of Dollars)	**Nine Months Ended Sept. 30, 2009**	**2008**
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 4,169	$ 6,315
Contracts realized or settled during the period	(14,499)	(3,911)
Commodity trading contract additions and changes during period	17,254	2,238
Fair value of commodity trading net contract assets outstanding at Sept. 30	$ 6,924	$ 4,642

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At Sept. 30, 2009, the fair values by source for the commodity trading net asset balances were as follows:

(Thousands of Dollars)	Source of Fair Value	Futures / Forwards 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	$ (625)	$ 861	$	$	$ 236
	2	1,511	3,952	256		5,719
PSCo	1	(1,607)	960			(647)
	2	968	303	444		1,715
		$ 247	$ 6,076	$ 700	$	$ 7,023

(Thousands of Dollars)	Source of Fair Value	Options 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	$ (99)	$	$	$	$ (99)
		$ (99)	$	$	$	$ (99)

(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*, hedge transactions and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations.

At Sept. 30, 2009, a 10 percent increase in market prices over the next 12 months for commodity trading contracts would increase pretax income from continuing operations by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.3 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. VaR is calculated on a consolidated basis. The VaRs for the commodity trading operations were:

Change from

	Period Ended Sept. 30, 2009	Period Ended June 30, 2009	VaR Limit	Average	High	Low
Commodity Trading(a)	$ 0.46	$ (0.17)	$ 5.00	$ 0.45	$ 1.51	$ 0.16

(a) Includes transactions for NSP-Minnesota and PSCo.

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.

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At Sept. 30, 2009, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $6.1 million annually, or approximately $1.5 million per quarter. See Note 10 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries interest rate derivatives.

Xcel Energy and its subsidiaries also maintain trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At Sept. 30, 2009, these funds were invested in a diversified portfolio of taxable and municipal fixed income securities 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 the nonperformance of a counterparty with respect to its 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.

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 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. Volatility in financial markets could increase Xcel Energy s credit risk.

Fair Value Measurements

Xcel Energy adopted new accounting and disclosure guidance on fair value measurements on Jan. 1, 2008 which established 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 12 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 immaterial to the fair value of commodity derivative assets at Sept. 30, 2009. 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 other comprehensive income 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 this credit risk was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2009.

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 5 percent and 36 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2009.

Determining the fair value of a FTR 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 $44.0 million and $7.7 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2009.

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 $20.1 million and $12.0 million of estimated fair values, respectively, for commodity forwards and options held at Sept. 30, 2009.

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 risk-based adjustments to estimated yield and forecasted prepayments are often significant to these valuations. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $98.2 million in the

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nuclear decommissioning fund at Sept. 30, 2009 (approximately 7 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

(Millions of Dollars)	Nine Months Ended Sept. 30, 2009	2008
Cash provided by (used in) operating activities		
Continuing operations	$ 1,646	$ 1,222
Discontinued operations	(17)	(11)
Total	$ 1,629	$ 1,211

Cash provided by operating activities for continuing operations increased by $424 million for the first nine months of 2009, compared with the first nine months of 2008. This increase was due to changes in working capital activity as a result of declining natural gas prices, partially offset by increased funding of the pension liability due to market performance.

(Millions of Dollars)	Nine Months Ended Sept. 30, 2009	2008
Cash used in investing activities	$ (1,294)	$ (1,585)

Cash used in investing activities for continuing operations decreased by $291 million for the first nine months of 2009, compared with the first nine months of 2008. The decrease was due to reduced capital expenditures as well as reduced investment in the WYCO pipeline and storage project.

(Millions of Dollars)	Nine Months Ended Sept. 30, 2009	2008
Cash (used in) provided by financing activities	$ (492)	$ 706

Cash used in financing activities for continuing operations increased by $1,198 million for the first nine months of 2009, compared with the first nine months of 2008. The increase is primarily due to fewer proceeds from the issuances of long-term debt and common stock in the first nine months of 2009, as well as repayment of long-term debt.

Capital Sources

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.

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.

Totem Gas Storage Facilities In 1999, WYCO was formed as a joint venture with CIG to develop and lease natural gas pipeline, storage, and compression facilities. Xcel Energy has a 50 percent ownership interest in WYCO. In June 2009, having achieved certain phases of construction, Totem was placed in service. WYCO will lease Totem to CIG, and CIG will operate the facilities, providing natural gas storage services to PSCo under a service arrangement that commenced on July 1, 2009.

Xcel Energy accounts for PSCo s service arrangement with CIG as a capital lease in accordance with the authoritative guidance on lease accounting. As a result, Xcel Energy has recorded a total of $67 million of Totem storage, leaseholds, and rights assets as property held under capital leases as of Sept. 30, 2009. WYCO is expected to incur approximately $20 million of additional construction costs to complete construction and make Totem operational at full storage capacity.

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Economic Stimulus Plan On Feb. 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009, referred to as the federal stimulus bill, which includes appropriations into many energy industry-related areas. Xcel Energy has reviewed the stimulus package and DOE application requirements to determine whether federal funding should be used for investments or upgrades to its system. Xcel Energy has had several conversations with state utility commissions and state governments within its service territories regarding the stimulus bill and has identified several areas of interest including renewable energy, energy efficiency, transmission and smart grid technologies. Xcel Energy has submitted applications for funding of certain projects; however, we do not expect this to have a material effect on Xcel Energy s financial position or results of operations.

Regulation of Derivatives The U.S. House of Representatives recently passed the ACES and there are several other bills which have been introduced regarding regulation of derivative transactions. One provision within the ACES bill and the other bills introduced require the regulation of all energy derivative and swap transactions. As passed by the House, the ACES bill 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. Xcel Energy will further analyze the provisions of this complex legislation to understand potential financial impacts and risk to Xcel Energy, but based on our preliminary analysis the margin requirements could be significant. In October 2009, the House Financial Institutions Committee held a hearing on additional proposed legislation submitted by Chairman Franks titled, the Over-the-Counter Derivatives Markets Act of 2009. The proposed legislation appears to contain less onerous language than the ACES bill; however, Xcel Energy is reviewing the proposal.

Short-Term Investments Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Sept. 30, 2009, approximately $16 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 Board 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.

Money Pool Xcel Energy has established a utility money pool arrangement that allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates.

The utility money pool arrangement does not allow loans from the utility subsidiaries to the holding company. NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions.

The borrowings or loans outstanding at Sept. 30, 2009, and the short-term borrowing limits from the money pool are as follows:

(Millions of Dollars)	Borrowings (Loans)	Total Borrowing Limits
Xcel Energy	$	$
NSP-Minnesota	117	250
PSCo	(27)	250
SPS	(90)	100

Credit Facilities As of Oct. 21, 2009, Xcel Energy had the following credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility	Drawn(a)	Available	Cash	Liquidity	Maturity
NSP-Minnesota	$ 482.2	$ 170.8	$ 311.4	$ 0.2	$ 311.6	December 2011
PSCo	675.1	4.6	670.5	13.1	683.6	December 2011
SPS	247.9	10.0	237.9	3.6	241.5	December 2011
Xcel Energy Holding Company	771.6	371.1	400.5	1.7	402.2	December 2011
NSP-Wisconsin(b)				21.8	21.8	
Total	$ 2,176.8	$ 556.5	$ 1,620.3	$ 40.4	$ 1,660.7	

(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 short-term borrowing agreement with NSP-Minnesota.

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Credit Agency Ratings The access of and cost of short-term and long-term borrowings are affected by regulatory actions, capital market conditions and credit agency ratings. The following ratings reflect the views of Moody s Investor Services, Inc. (Moody s), Standard & Poor s Ratings Services (Standard & Poor s), and Fitch Ratings (Fitch). A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency.

On June 10, 2009, Standard & Poor s affirmed its credit ratings and revised the outlook on Xcel Energy and its rated subsidiaries to positive from stable. On Aug. 3, 2009, Moody s upgraded the majority of senior secured debt ratings of investment-grade regulated utilities by one notch. As of Oct. 30, 2009, the following table represents the credit ratings assigned to various Xcel Energy companies:

Company	Credit Type	Moody s	Standard & Poor s	Fitch
Xcel Energy	Senior Unsecured Debt	Baa1	BBB	BBB+
Xcel Energy	Commercial Paper	P-2	A-2	F2
NSP-Minnesota	Senior Unsecured Debt	A3	BBB+	A
NSP-Minnesota	Senior Secured Debt	A1	A	A+
NSP-Minnesota	Commercial Paper	P-2	A-2	F1
NSP-Wisconsin	Senior Unsecured Debt	A3	A-	A
NSP-Wisconsin	Senior Secured Debt	A1	A	A+
PSCo	Senior Unsecured Debt	Baa1	BBB+	A-
PSCo	Senior Secured Debt	A2	A	A
PSCo	Commercial Paper	P-2	A-2	F2
SPS	Senior Unsecured Debt	Baa1	BBB+	BBB+
SPS	Commercial Paper	P-2	A-2	F2

Note: Moody s highest credit rating for debt is Aaa and lowest investment grade rating is Baa3. Both Standard & Poor s and Fitch s highest credit rating for debt are AAA and lowest investment grade rating is BBB-. Moody s prime ratings for commercial paper range from P-1 to P-3. Standard & Poor s ratings for commercial paper range from A-1 to A-3. Fitch s ratings for commercial paper range from F1 to F3.

In the event of a downgrade of its credit ratings to below investment grade, Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy all or a part of its exposures under guarantees outstanding. See discussion of guarantees at Note 11 to the consolidated financial statements. Xcel Energy has no explicit credit rating requirements or hard triggers in its debt agreements.

Registration Statements Xcel Energy s articles of incorporation authorize the issuance of 1 billion shares of common stock. As of Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy had approximately 456 and 454 million shares, respectively, of common stock outstanding. In addition, Xcel Energy s articles of incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On Sept. 30, 2009 and Dec. 31, 2008, Xcel Energy had approximately 1 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 $1.5 billion of debt and common equity securities.

- NSP-Minnesota has $1.0 billion of debt securities available under its current effective registration statement.
- PSCo has $400 million of debt securities available under its registration statement that became effective on Feb. 20, 2009.
- NSP-Wisconsin filed a registration statement in June 2008 that has $50 million 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 securities to refinance retiring maturities, reduce short-term debt, fund construction programs and for other general corporate purposes.

NSP-Minnesota plans to issue $300 million of first mortgage bonds in November. The proceeds will be used to repay short-term debt, which was used to fund the payment of a $250 million unsecured note that matured on Aug. 1, 2009, and for general corporate purposes.

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

Earnings Guidance

Based on current projections, we expect 2009 earnings to be near the mid-point of our guidance range of $1.45 to $1.55 per share. Key assumptions are detailed below:

- Normal weather patterns are experienced for the remainder of the year.
- Reasonable regulatory outcomes are achieved in various rate cases and other regulatory decisions which may occur during the year.
- Various riders, associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, are expected to increase revenue by approximately $50 million to $60 million over 2008 levels.
- Weather adjusted electric retail sales decline by approximately 2 percent.
- Weather adjusted retail firm natural gas sales decline by approximately 1 percent.
- Capacity costs are projected to increase approximately $45 million over 2008 levels. Capacity costs at PSCo are recovered under the purchased capacity cost adjustment.
- Operating and maintenance expenses are projected to increase $140 million over 2008 levels. In 2008, nuclear outage expense decreased due to a change in recovery method related to costs associated with refueling outages and there was no accrual in 2008 for the annual performance based incentive plan. The increase reflects the following:
- Nuclear (including outage amortization) $55 million
- Pension and medical $35 million
- Other $50 million (including $35 million of incentive compensation)
- Depreciation and amortization expense is projected to decline by approximately $10 million compared with 2008 levels. This reflects the recent MPUC decision to extend the depreciation life of the Prairie Island nuclear plant by 10 years.
- Interest expense increases approximately $15 million to $20 million over 2008 levels.
- Allowance for funds used during construction equity is projected to increase by $10 million to $15 million over 2008 levels.
- An effective tax rate for continuing operations of approximately 34 percent to 36 percent.
- Average common stock and equivalents of approximately 457 million shares.

Item 3 QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See discussion in Derivatives, Risk Management and Market Risks in Item 2 Management s Discussion and Analysis.

Item 4 CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports under the Exchange Act 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 the end of the period covered by this report, 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 our disclosure controls and 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.

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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, 2008 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, 2008, which is incorporated herein by reference.

We are subject to credit risks.

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

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

One alternative available to address counterparty credit risk is to transact on liquid commodity exchanges. The credit risk is then socialized through the exchange central clearinghouse function. While exchanges do remove counterparty credit risk, all participants are subject to margin requirements, which creates an additional need for liquidity to post margin as exchange positions change value daily. Additional margin requirements could impact our liquidity.

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

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

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. Likewise, the EPA has drafted regulations pursuant to which GHGs from certain stationary sources would be regulated under the Clean Air Act by March 2010. Xcel Energy s 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. Xcel Energy is also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in the Note 7, Commitments and Contingent Liabilities, in our Notes to our Consolidated Financial Statements. While Xcel Energy believes such lawsuits are without merit, an adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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Many of the federal and state climate change legislative proposals, such as ACES, 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. The impact of legislation and regulations, including a cap and trade structure, on Xcel Energy and its 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. Another important factor is Xcel Energy s 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 Xcel Energy or its operating subsidiaries. If our regulators do not allow us to recover all or a part of the cost of capital investment or the operating and maintenance costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

For further discussion see the Management s Discussion and Analysis section and Note 7 to the consolidated financial statements.

Item 2 UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

Period	**Total Number of Shares Purchased**	**Average Price Paid per Share**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs**
July 1, 2009 July 31, 2009				
Aug. 1, 2009 Aug. 31, 2009 (a)	136,846	$ 19.77		
Sept. 1, 2009 Sept. 30, 2009				
Total	136,846			

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

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Item 6 EXHIBITS

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* Indicates incorporation by reference

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)).
10.01	Credit Agreement dated Dec. 14, 2006 between Xcel Energy and various lenders.
10.02	Credit Agreement dated Dec. 14, 2006 between NSP-Minnesota and various lenders.
10.03	Credit Agreement dated Dec. 14, 2006 between PSCo and various lenders.
10.04	Credit Agreement dated Dec. 14, 2006 between SPS and various lenders.
10.05	Second Amendment to the Xcel Energy 2005 Omnibus Incentive Plan (renaming it the Xcel Energy 2005 Long-Term Incentive Plan).
10.06	Amendment dated Aug. 26, 2009 to the Xcel Energy Senior Executive Severance and Change-in-Control Policy
10.07	Second Amendment to the Xcel Energy Inc. Executive Annual Incentive Award Plan (Effective May 25, 2005).
10.08	Xcel Energy Inc. Executive Annual Incentive Award Plan Form of Restricted Stock Agreement.
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)
Oct. 30, 2009	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)