XCEL ENERGY INC
Form 10-Q
July 31, 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 June 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. xYes oNo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). xYes oNo

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

Large accelerated filer x	Accelerated filer £
Non-accelerated filer £ (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 xNo

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

Class	**Outstanding at July 17, 2009**
Common Stock, $2.50 par value	455,725,244 shares

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

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PART I FINANCIAL INFORMATION

Item 1 FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(amounts in thousands, except per share data)

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating revenues				
Electric	$ 1,733,695	$ 2,154,383	$ 3,620,252	$ 4,127,697
Natural gas	265,884	443,613	1,054,560	1,477,740
Other	16,504	17,519	36,813	38,466
Total operating revenues	2,016,083	2,615,515	4,711,625	5,643,903
Operating expenses				
Electric fuel and purchased power	797,101	1,269,422	1,721,849	2,357,502
Cost of natural gas sold and transported	146,388	319,800	738,153	1,142,927
Cost of sales other	3,987	4,114	9,353	9,567
Other operating and maintenance expenses	472,401	456,781	944,295	917,802
Conservation and demand side management program expenses	41,417	29,226	86,636	64,795
Depreciation and amortization	202,348	207,774	411,063	413,381
Taxes (other than income taxes)	73,073	68,562	150,111	147,975
Total operating expenses	1,736,715	2,355,679	4,061,460	5,053,949
Operating income	279,368	259,836	650,165	589,954
Interest and other income, net	3,019	9,161	5,371	17,534
Allowance for funds used during construction equity	18,720	14,939	36,947	29,159
Interest charges and financing costs				
Interest charges includes other financing costs of $5,114, $5,141, $10,152 and $10,132, respectively	139,297	133,723	281,100	265,894
Allowance for funds used during construction debt	(9,845)	(9,596)	(20,073)	(19,123)
Total interest charges and financing costs	129,452	124,127	261,027	246,771
Income from continuing operations before income taxes and equity earnings	171,655	159,809	431,456	389,876
Income taxes	57,846	54,819	144,971	131,213
Equity earnings of unconsolidated subsidiaries	3,255	483	6,397	805
Income from continuing operations	117,064	105,473	292,882	259,468
Income (loss) from discontinued operations, net of tax	43	99	(1,708)	(778)
Net income	117,107	105,572	291,174	258,690

Dividend requirements on preferred stock	1,060	1,060	2,120	2,120
Earnings available to common shareholders	$ 116,047	$ 104,512	$ 289,054	$ 256,570
Weighted average common shares outstanding:				
Basic	456,307	430,811	455,753	430,187
Diluted	456,766	435,868	456,362	435,360
Earnings per average common share:				
Basic	$ 0.25	$ 0.24	$ 0.63	$ 0.60
Diluted	0.25	0.24	0.63	0.59
Cash dividends declared per common share	0.25	0.24	0.48	0.47

See Notes to Consolidated Financial Statements

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

(amounts in thousands of dollars)

	Six Months Ended June 30, 2009	2008
Operating activities		
Net income	$ 291,174	$ 258,690
Remove loss from discontinued operations	1,708	778
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	433,745	453,699
Nuclear fuel amortization	37,713	31,045
Deferred income taxes	146,903	137,430
Amortization of investment tax credits	(3,475)	(3,895)
Allowance for equity funds used during construction	(36,947)	(29,159)
Equity earnings of unconsolidated subsidiaries	(6,397)	(805)
Dividends from equity method investees	13,473	
Share-based compensation expense	17,944	10,512
Net realized and unrealized hedging and derivative transactions	51,388	(7,887)
Changes in operating assets and liabilities:		
Accounts receivable	190,491	86,265
Accrued unbilled revenues	264,308	145,774
Inventories	229,504	26,523
Recoverable purchased natural gas and electric energy costs	(31,891)	(113,318)
Other current assets	1,695	23,046
Accounts payable	(310,589)	(36,874)
Net regulatory assets and liabilities	32,886	8,742
Other current liabilities	(43,239)	(123,274)
Change in other noncurrent assets	5,898	(3,370)
Change in other noncurrent liabilities	(157,191)	(40,144)
Operating cash flows used in discontinued operations	(3,335)	(20,576)
Net cash provided by operating activities	1,125,766	803,202
Investing activities		
Utility capital/construction expenditures	(947,474)	(1,040,327)
Allowance for equity funds used during construction	36,947	29,159
Purchase of investments in external decommissioning fund	(1,014,130)	(441,802)
Proceeds from the sale of investments in external decommissioning fund	1,012,705	420,106
Investment in WYCO Development LLC	(25,254)	(37,793)
Change in restricted cash	33	2,197
Other investments	3,537	3,437
Net cash used in investing activities	(933,636)	(1,065,023)
Financing activities		
Repayment of short-term borrowings, net	(85,250)	(415,678)
Proceeds from issuance of long-term debt	394,897	892,710
Repayment of long-term debt, including reacquisition premiums	(168,971)	(1,825)
Proceeds from issuance of common stock	2,665	3,015
Dividends paid	(203,859)	(199,755)
Net cash (used in) provided by financing activities	(60,518)	278,467
Net increase in cash and cash equivalents	131,612	16,646
Net (decrease) increase in cash and cash equivalents discontinued operations	(557)	3,105
Cash and cash equivalents at beginning of year	249,198	51,120
Cash and cash equivalents at end of quarter	$ 380,253	$ 70,871
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (250,990)	$ (224,278)
Cash paid for income taxes (net of refunds received)	(26,569)	(47,396)
Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 37,066	$ 30,943
Supplemental disclosure of non-cash financing transactions:		
Issuance of common stock for reinvested dividends and 401(k) plans	$ 36,076	$ 41,626

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(amounts in thousands of dollars)

	June 30, 2009	Dec. 31, 2008
Assets		
Current assets		
Cash and cash equivalents	$ 380,253	$ 249,198
Accounts receivable, net	721,410	900,781
Accrued unbilled revenues	478,906	743,479
Inventories	435,522	666,709
Recoverable purchased natural gas and electric energy costs	79,229	32,843
Derivative instruments valuation	118,790	101,972
Prepayments and other	253,188	263,906
Current assets held for sale and related to discontinued operations	91,393	56,641
Total current assets	2,558,691	3,015,529
Property, plant and equipment, net	18,201,097	17,688,720
Other assets		
Nuclear decommissioning fund and other investments	1,317,097	1,232,081
Regulatory assets	2,307,931	2,357,279
Derivative instruments valuation	310,241	325,688
Other	136,817	157,742
Noncurrent assets held for sale and related to discontinued operations	155,377	181,456
Total other assets	4,227,463	4,254,246
Total assets	$ 24,987,251	$ 24,958,495
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 458,751	$ 558,772
Short-term debt	370,000	455,250
Accounts payable	793,746	1,120,324
Taxes accrued	169,955	220,542
Accrued interest	170,475	168,632
Dividends payable	112,710	108,838
Derivative instruments valuation	73,195	75,539
Other	371,509	331,419
Current liabilities held for sale and related to discontinued operations	30,956	6,929
Total current liabilities	2,551,297	3,046,245
Deferred credits and other liabilities		
Deferred income taxes	2,963,448	2,792,560
Deferred investment tax credits	102,241	105,716
Regulatory liabilities	1,221,717	1,194,596
Asset retirement obligations	1,169,264	1,135,182
Derivative instruments valuation	328,210	340,802
Customer advances	309,370	323,445
Pension and employee benefit obligations	913,660	1,030,532
Other	190,582	168,352
Noncurrent liabilities held for sale and related to discontinued operations	3,121	20,656
Total deferred credits and other liabilities	7,201,613	7,111,841
Commitments and contingent liabilities		
Capitalization		
Long-term debt	8,055,638	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 outstanding shares: June 30, 2009 455,716,724; Dec. 31, 2008 453,791,770	7,073,723	6,963,741
Total liabilities and equity	$ 24,987,251	$ 24,958,495

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (UNAUDITED)

(amounts in thousands)

	Common Stock Issued		Additional	Retained	Accumulated Other	Total Common
	Shares	Par Value	Paid In Capital	Earnings	Comprehensive Income (Loss)	Stockholders' Equity
Three Months Ended June 30, 2009 and 2008						
Balance at March 31, 2008	430,512	$ 1,076,281	$ 4,293,053	$ 1,015,317	$ (27,603)	$ 6,357,048
Net income				105,572		105,572
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $241					247	247
Net derivative instrument fair value changes during the period, net of tax of $723					908	908
Unrealized loss - marketable securities, net of tax of $(67)					(101)	(101)
Comprehensive income for the period						106,626
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(102,341)		(102,341)
Issuances of common stock	405	1,011	7,489			8,500
Share-based compensation			5,697			5,697
Balance at June 30, 2008	430,917	$ 1,077,292	$ 4,306,239	$ 1,017,488	$ (26,549)	$ 6,374,470
Balance at March 31, 2009	455,256	$ 1,138,141	$ 4,710,666	$ 1,252,471	$ (52,196)	$ 7,049,082
Net income				117,107		117,107
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $255					372	372
Net derivative instrument fair value changes during the period, net of tax of $1,379					2,131	2,131
Unrealized gain - marketable securities, net of tax of $232					339	339
Comprehensive income for the period						119,949
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(112,113)		(112,113)
Issuances of common stock	461	1,151	9,347			10,498
Share-based compensation			7,367			7,367
Balance at June 30, 2009	455,717	$ 1,139,292	$ 4,727,380	$ 1,256,405	$ (49,354)	$ 7,073,723

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME (UNAUDITED)

(amounts in thousands)

	Common Stock Issued		Additional	Retained	Accumulated Other Comprehensive	Total Common Stockholders'
	Shares	Par Value	Paid In Capital	Earnings	Income (Loss)	Equity
Six Months Ended June 30, 2009 and 2008						
Balance at Dec. 31, 2007	428,783	$ 1,071,957	$ 4,286,917	$ 963,916	$ (21,788)	$ 6,301,002
EITF 06-4 adoption, net of tax of $(1,038)				(1,640)		(1,640)
Net income				258,690		258,690
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $876					58	58
Net derivative instrument fair value changes during the period, net of tax of $(1,067)					(4,718)	(4,718)
Unrealized loss - marketable securities, net of tax of $(67)					(101)	(101)
Comprehensive income for the period						253,929
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(201,358)		(201,358)
Issuances of common stock	2,134	5,335	7,541			12,876
Share-based compensation			11,781			11,781
Balance at June 30, 2008	430,917	$ 1,077,292	$ 4,306,239	$ 1,017,488	$ (26,549)	$ 6,374,470
Balance at Dec. 31, 2008	453,792	$ 1,134,480	$ 4,695,019	$ 1,187,911	$ (53,669)	$ 6,963,741
Net income				291,174		291,174
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $509					741	741
Net derivative instrument fair value changes during the period, net of tax of $2,180					3,331	3,331
Unrealized gain - marketable securities, net of tax of $168					243	243
Comprehensive income for the period						295,489
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(220,560)		(220,560)
Issuances of common stock	1,925	4,812	18,065			22,877
Share-based compensation			14,296			14,296
Balance at June 30, 2009	455,717	$ 1,139,292	$ 4,727,380	$ 1,256,405	$ (49,354)	$ 7,073,723

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of June 30, 2009 and Dec. 31, 2008; the results of its operations and changes in stockholders equity for the three and six months ended June 30, 2009 and 2008; and its cash flows for the six months ended June 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 June 30, 2009 up to July 31, 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 income statement. The reclassification did not have an impact on net income or earnings per share.

2. Accounting Pronouncements

Recently Adopted

Business Combinations (Statement of Financial Accounting Standards (SFAS) No. 141 (revised 2007)) In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), 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. SFAS No. 141(R) 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 SFAS No. 141(R) on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Noncontrolling Interests in Consolidated Financial Statements, an Amendment of Accounting Research Bulletin (ARB) No. 51 (SFAS No. 160) In December 2007, the FASB issued SFAS No. 160, 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. SFAS No. 160 was effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy implemented SFAS No. 160 on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133 (SFAS No. 161) In March 2008, the FASB issued SFAS No. 161, 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. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures including objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative contracts. SFAS No. 161 was effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008. Xcel Energy implemented SFAS No. 161 on Jan. 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For further discussion and SFAS No. 161 required disclosures, see Note 10 to the consolidated financial statements.

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Interim Disclosures about Fair Value of Financial Instruments (FASB Staff Position (FSP) FAS 107-1 and Accounting Principles Board (APB) 28-1) In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, which amends SFAS No. 107*, Disclosures About Fair Value of Financial Instruments*, and APB Opinion No. 28, *Interim Financial Reporting*, to require disclosures regarding the fair value of financial instruments in interim financial statements. FSP FAS 107-1 and APB 28-1 was effective for interim periods ending after June 15, 2009. Xcel Energy implemented FSP FAS 107-1 and APB 28-1 on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements. For FSP FAS 107-1 and APB 28-1 required disclosures, see Note 11 to the consolidated financial statements.

Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly (FSP FAS 157-4) In April 2009, the FASB issued FSP FAS 157-4, which provides additional guidance for estimating fair value in accordance with SFAS No. 157, *Fair Value Measurements*, when the volume and level of market activity for an asset or liability have significantly decreased. FSP FAS 157-4 emphasizes that even if there has been a significant decrease in the volume and level of market activity for the asset or liability, fair value still represents the exit price in an orderly transaction between market participants. FSP FAS 157-4 was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented FSP FAS 157-4 on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Recognition and Presentation of Other-Than-Temporary Impairments (FSP FAS 115-2 and FAS 124-2) In April 2009, the FASB issued FSP FAS 115-2 and FAS 124-2, 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. FSP FAS 115-2 and FAS 124-2 was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented FSP FAS 115-2 and FAS 124-2 on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Subsequent Events (SFAS No. 165) In May 2009, the FASB issued SFAS No. 165, which establishes general standards of accounting and disclosure for events that occur after the balance sheet date but before financial statements are issued. The accounting guidance contained in SFAS No. 165 is consistent with the auditing literature widely used for accounting and disclosure of subsequent events, however, SFAS No. 165 requires an entity to disclose the date through which subsequent events have been evaluated. SFAS No. 165 was effective for interim and annual periods ending after June 15, 2009. Xcel Energy implemented SFAS No. 165 on April 1, 2009, and the implementation did not have a material impact on its consolidated financial statements.

Recently Issued

Employers Disclosures about Postretirement Benefit Plan Assets (FSP FAS 132(R)-1) In December 2008, the FASB issued FSP FAS 132(R)-1, which amends SFAS No. 132 (revised 2003), *Employers Disclosures about Pensions and Other Postretirement Benefits,* to expand an employer s required disclosures about 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. FSP FAS 132(R)-1 is effective for fiscal years ending after Dec. 15, 2009. Xcel Energy does not expect the implementation of FSP FAS 132(R)-1 to have a material impact on its consolidated financial statements.

Amendments to FASB Interpretation No. 46(R) (SFAS No. 167) In June 2009, the FASB issued SFAS No. 167, which amends the consolidation guidance applicable to variable interest entities. The amendments will significantly affect various elements of consolidation guidance under FASB Interpretation No. 46(R), including guidance for determining whether an entity is a variable interest entity and whether an enterprise is a variable interest entity s primary beneficiary. SFAS No. 167 is effective for fiscal years beginning after Nov. 15, 2009. Xcel

Energy is currently evaluating the impact of SFAS No. 167 on its consolidated financial statements.

The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162 (SFAS No. 168) In June 2009, the FASB issued SFAS No. 168, which confirms that the FASB Accounting Standards Codification (Codification) will become the single source of authoritative GAAP, other than the guidance put forth by the SEC. All other accounting literature not included in the Codification will be considered non-authoritative. SFAS No. 168 is effective for interim and annual periods ending after Sept. 15, 2009. Xcel Energy expects the implementation of SFAS No. 168 to have no impact on its consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)		June 30, 2009		Dec. 31, 2008
Accounts receivable, net				
Accounts receivable	$	781,586	$	965,020
Less allowance for bad debts		(60,176)		(64,239)
	$	721,410	$	900,781
Inventories				
Materials and supplies	$	168,664	$	158,709
Fuel		176,552		227,462
Natural gas		90,306		280,538
	$	435,522	$	666,709
Property, plant and equipment, net				
Electric plant	$	22,416,942	$	21,601,094
Natural gas plant		3,063,906		3,004,088
Common and other property		1,470,431		1,497,162
Construction work in progress		1,686,177		1,832,022
Total property, plant and equipment		28,637,456		27,934,366
Less accumulated depreciation		(10,737,081)		(10,501,266)
Nuclear fuel		1,694,008		1,611,193
Less accumulated amortization		(1,393,286)		(1,355,573)
	$	18,201,097	$	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)		June 30, 2009		Dec. 31, 2008
Cash	$	10,088	$	10,645
Accounts receivable, net		827		209
Deferred income tax benefits		49,130		39,422
Other current assets		31,348		6,365
Current assets held for sale and related to discontinued operations	$	91,393	$	56,641
Deferred income tax benefits	$	150,571	$	150,912
Other noncurrent assets		4,806		30,544
Noncurrent assets held for sale and related to discontinued operations	$	155,377	$	181,456
Accounts payable	$	522	$	760
Other current liabilities		30,434		6,169

Current liabilities held for sale and related to discontinued operations	$	30,956	$	6,929
Noncurrent liabilities held for sale and related to discontinued operations	$	3,121	$	20,656

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5. Income Taxes

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) 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. In the third quarter of 2008, the IRS commenced an examination of tax years 2006 and 2007. As of June 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 June 30, 2009, Xcel Energy s earliest open tax years in which an audit can be initiated 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 $33.5 million on June 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 June 30, 2009 and Dec. 31, 2008. The unrecognized tax benefit amounts reported in continuing operations were increased by payables associated with NOL and tax credit carryovers of $1.0 million on June 30, 2009 and reduced by the tax benefits associated with NOL and tax credit carryovers of $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 $23.9 million on June 30, 2009 and $26.5 million on Dec. 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $7.0 million and $9.2 million of tax positions on June 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 $26.5 million and $26.3 million of tax positions on June 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 decrease in the unrecognized tax benefit balance reported in continuing operations of $4.2 million from April 1, 2009 to June 30, 2009, was due to the resolution of certain federal audit matters, partially offset by 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. At this time, due to the uncertain nature of the audit process, it is not reasonably possible to estimate an overall range of possible change.

The 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 second quarter of 2009 was not material. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the second quarter of 2008 was $0.4 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $2.2 million on June 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 second quarter of 2009 reduced interest expense by $0.1 million. The amount reported within interest charges related to unrecognized tax benefits in discontinued operations in the second quarter of 2008 reduced interest expense by $0.3 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $1.8 million on June 30, 2009 and $1.5 million on Dec. 31, 2008.

No amounts were accrued for penalties as of June 30, 2009 and 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, or 6.05 percent. The request is based on a 2009 forecast test-year, an electric rate base of $4.1 billion, a requested return on equity (ROE) of 11.0 percent and an equity ratio of 52.5 percent.

In December 2008, the MPUC approved an interim rate increase of $132 million, or 5.12 percent, effective Jan. 2, 2009. The primary difference between interim rate levels approved and NSP-Minnesota s request of $156 million is due to a previously authorized ROE of 10.54 percent and NSP-Minnesota s requested ROE of 11.0 percent.

On April 7, 2009, intervenors submitted direct testimony. The Office of Energy Security (OES) recommended a revenue increase of $72 million, based on a ROE of 10.88 percent and an equity ratio of 52.5 percent. The recommended revenue increase included recognition of a 10-year life extension of the Prairie Island nuclear plant, resulting in a decrease of approximately $40 million in depreciation and decommissioning expenses and rejection of NSP-Minnesota s proposed nuclear rate stability plan. These adjustments would reduce NSP-Minnesota s overall revenue deficiency while at the same time reducing expense accruals by $40 million.

On May 5, 2009, NSP-Minnesota filed rebuttal testimony that reduced its rate increase request to $138 million. The reduction of $18 million is primarily associated with cost decreases in certain commodities, management initiatives to defer a wage increase for non-bargaining employees, reductions in employee expenses and lower projected short-term capacity costs since the time of filing. Partially offsetting these reductions are increases in health care and pension costs. The rebuttal testimony offered an alternative proposal to reflect a three-year life extension for both decommissioning and depreciation expense accruals for the Prairie Island nuclear plant. The revenue requirement under NSP-Minnesota s alternative proposal was $121 million.

Also on May 5, 2009, the Office of the Attorney General (OAG) filed testimony that recommended disallowance of certain Board of Directors and employees expenses, the aggregate of which NSP-Minnesota estimates to be less than $1.5 million. In addition, the OAG recommended use of different allocators for corporate costs that would reduce the deficiency by $3.4 million.

On May 26, 2009, parties filed surrebuttal testimony. The OES revised its revenue deficiency to approximately $92 million. The OES continues to recommend a 10-year extension of NSP-Minnesota s nuclear decommissioning and depreciation expense at Prairie Island and a 10.88 percent ROE. NSP-Minnesota s surrebuttal testimony proposed an additional $1 million reduction to its rebuttal revenue deficiency.

At the time of hearing, the OES revised its request to $90 million compared to NSP-Minnesota s initial request of $119 million. Other than the appropriate extension period for Prairie Island decommissioning and depreciation, the difference between NSP-Minnesota s position and the OES is approximately $6 million. The OAG has one unresolved financial issue related to cost allocations whereby it is seeking a disallowance of approximately $3.4 million. Contested case hearings were completed before an administrative law judge (ALJ) in June 2009, and initial and reply briefs were filed in July. The ALJ is expected to issue a recommended decision in late August 2009, and a final decision from the MPUC is expected in October 2009.

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider In November 2006, the MPUC approved a TCR rider pursuant to legislation, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. On Oct. 30, 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. On June 25, 2009, the MPUC approved the rider request. The revised TCR rate recovery factors were placed into effect in July 2009.

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Renewable Energy Standard (RES) Rider In March 2008, the MPUC approved an RES rider to recover the costs for utility-owned projects implemented in compliance with the RES, and the RES rider was implemented on April 1, 2008. Under the rider, NSP-Minnesota recovered approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100-megawatt (MW) wind project. In 2008, NSP-Minnesota submitted the RES rider for recovery of approximately $22 million in 2009 attributable to the Grand Meadow wind farm. On Feb. 12, 2009, the MPUC approved the rider request but required that the issue of whether these costs should be moved to base rates in the currently pending electric rate case or left in the rider, as NSP-Minnesota has proposed, to be addressed through supplemental testimony in the rate case.

Metropolitan Emissions Reduction Project (MERP) Rider On Oct. 1, 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 $114 million in 2009, an increase of approximately $23 million over 2008. New rates went into effect automatically on Jan. 1, 2009, as stipulated. MPUC approval is still pending.

State Energy Policy Rider On March 2, 2009, NSP-Minnesota filed a proposed State Energy Policy 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 $0.1 million from its natural gas customers in 2009. MPUC approval is pending.

Annual Automatic Adjustment Report for 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). The 2008 electric annual automatic adjustment report is pending initial comments, scheduled for August 2009, and MPUC action. 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 is pending.

Conservation Incentive Filing As a result of 2007 legislation, Minnesota state agencies convened a work group near the end of 2008 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. Each Minnesota utility was required to file a separate plan for implementing the shared savings approach. On July 1, 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 from anywhere from 0 to approximately 15 percent of the net present value of benefits, depending on the level of savings achieved. Comments on NSP-Minnesota s proposal are due in August 2009.

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 the May to July 2008 timeframe, NSP-Minnesota rebilled approximately 5,000 of these customers for their estimated consumption during the period the modules registered no consumption and then ceased rebilling as both the MPUC and North Dakota Public Service Commission (NDPSC) opened investigations into this matter. NSP-Minnesota has additionally initiated dispute resolution provisions under the terms of its agreement with its provider of the AMR modules and meter reading services.

The NDPSC approved NSP-Minnesota s proposed resolution in April 2009. NSP-Minnesota began implementing the service quality credits and the rebilling of remaining North Dakota customers in June 2009. NSP-Minnesota rebilled North Dakota customers approximately $1.5 million for the estimated gas usage during the module failure period. On March 6, 2009, NSP-Minnesota filed a request with the MPUC to rebill the remaining Minnesota customers experiencing a module failure, reiterated the commitments made in previous filings and proposed a $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 will have lapsed from the time of meter failures to the expected time (if approved) for rebilling. 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.

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Annual Review of Remaining Lives On Feb. 17, 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 OES recommended *provisional* approval to ensure that the decisions in this depreciation docket do not have unintended consequences in the pending NSP-Minnesota electric rate case. The OES recommended a 10-year lengthening of depreciation life. On July 1, 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 generating plant. Consistent with the OES recommendation, the MPUC deferred the determination of the appropriate depreciation rates for the Prairie Island generating plant to the pending NSP-Minnesota electric rate case.

Nuclear Decommissioning Expenses On June 12, 2009, the MPUC issued its order in its review of NSP-Minnesota s 2009 nuclear plant decommissioning accrual. The order extended the decommissioning life for Prairie Island by ten years rather than the three years proposed by NSP-Minnesota. The effect of this order was to reduce from $32 million to zero the amount of future nuclear decommissioning expenses that must be collected from customers, effective Jan. 1, 2009.

The MPUC order also directed NSP-Minnesota to proceed with a filing to propose a method to return to customers their contributions of $22.9 million made to the external escrow decommissioning fund for the Monticello nuclear plant.

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

South Dakota Electric Rate Case On June 30, 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 of 11.25 percent, and an equity ratio of 51.63 percent. Rates are expected to be in effect on or before Jan. 1, 2010, based on statutory requirements in South Dakota.

NSP-Minnesota South Dakota TCR and Environmental Cost Recovery (ECR) Rate Riders In December 2008, the SDPUC approved two rate riders for recovery of transmission investments and environmental costs effective Feb. 1, 2009. The TCR rate rider is set to recover approximately $1.9 million during 2009. The ECR rate rider is set to recover approximately $2.5 million during 2009.

Both rate riders were allowed a ROE of 9.5 percent according to the terms of their respective settlement agreements. However, the SDPUC may order that an appropriate ROE value based on the current South Dakota rate case be utilized under the rider mechanism, subject to true-up for the period from July 1, 2008 to the effective date of the order. As indicated previously, the South Dakota general rate case, filed June 30, 2009, uses a 2008 test-year.

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 after the close of the day-ahead energy market 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 regarding the components of the RSG charge. In the compliance proceeding, the FERC has issued numerous orders, attempting to refine and clarify the RSG charge. With the issuance of these orders (including orders on rehearing), the FERC has directed certain refunds to market participants, but has subsequently refined or waived various refund requirements. Most recently, the FERC issued an order in June 2009 relating to MISO s ongoing RSG-compliance proceeding. The FERC granted rehearing in part of certain earlier orders directing refunds to correct a rate mismatch in the RSG charge. Specifically, the June 2009 order waived refunds for the period up until Nov. 5, 2007, and directed MISO to correct the rate mismatch (through refunds) from Nov. 5, 2007 to Nov. 10, 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 and the submission of briefs and evidence by parties, 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 Nov. 10, 2008, the date of the FERC order determining that the allocation to market participants of the RSG charges was unjust and unreasonable. The FERC affirmed that a new RSG charge should be implemented from Nov. 10, 2008 on a prospective basis. MISO s Feb. 23, 2009 compliance revisions to the RSG charge, as amended, are still pending at the FERC.

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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 request(s) 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 (from May 2009 and June 2009, respectively), are both subject to pending requests for rehearing. The D.C. Circuit proceedings are being held in abeyance pending final action in the FERC proceedings.

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, approving an electric rate increase of approximately $39.4 million, or 8.1 percent, and new rates went into effect. 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.

On June 12, 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 decreases to approximately $1.4 million, effective Jan. 1, 2009. In accordance with the PSCW s final order, NSP-Wisconsin has established a refund liability of $3.6 million through June 30, 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.

2010 Electric and Natural Gas Rate Case On June 1, 2009, NSP-Wisconsin filed a combined electric and natural gas rate application. NSP-Wisconsin requested an overall increase in annual retail electric revenues of approximately $30.4 million, or an increase of 5.7 percent. The rate filing is based on a 2010 calendar year budget, an electric net investment rate base of approximately $644 million, a regulatory equity ratio of 53.12 percent, and NSP-Wisconsin s currently authorized ROE of 10.75 percent. NSP-Wisconsin did not request any change to natural gas rates. NSP-Wisconsin s gas net investment rate base is approximately $81 million. NSP-Wisconsin has requested the PSCW to issue an order approving this application in time to allow for new rates to be effective Jan. 1, 2010.

Other

2009 Electric Fuel Cost Recovery NSP-Wisconsin s fuel and purchased power costs for February 2009 were approximately $1.4 million, or 10.8 percent lower than authorized in the 2009 electric rate case limited reopener, which are outside the monthly and cumulative variance ranges for monitored fuel costs established by the PSCW. On April 16, 2009, the PSCW opened a proceeding to 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 June were approximately $7.6 million less than authorized, primarily due to lower load and lower market prices for fuel and purchased power. 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 reserve of $5.6 million to reflect the likelihood that the PSCW will order the company to refund a portion of the electric revenues collected through June 30, 2009.

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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 is 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 June 26, 2009, one party filed for reconsideration of the CPUC s decision approving the settlement. On July 14, 2009, the CPUC denied the request for reconsideration. PSCo implemented new rates on July 1, 2009.

PSCo 2010 Electric Rate Case On May 1, 2009, PSCo filed with the CPUC a request to increase Colorado electric rates by $180 million effective in 2010. The rate filing is based on a 2010 calendar year budget and includes a requested rate of return on equity 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. Overall, the primary drivers for the increase are related to placing the Comanche Unit 3 in service, the remaining months of recovery of Ft. St. Vrain, increased investment in the distribution system and higher operating and maintenance expenses.

This request also shifts all or a portion of the current costs associated with the Air Quality Improvement Rider and the Demand Side Management Cost Adjustment into base rates, which will have no impact on customer bills.

The following procedural schedule has been established:

- Intervenor testimony on Sept. 4, 2009;
- Cross and rebuttal testimony on Oct. 13, 2009;
- Evidentiary hearings are scheduled for Oct. 26-Nov. 6, 2009; and

- Statements of position on Nov. 16, 2009.

PSCo expects the CPUC to reach a decision regarding the 2010 rate case within approximately eight months. Therefore, the new base rates approved in this proceeding are expected to be effective on Jan 1, 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 on Nov. 3, 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 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

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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 is 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.

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 to JD Wind for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind for energy produced from its qualifying facility (QF) are appropriate and in accordance with SPS filed tariffs with the PUCT. On March 25, 2009, the ALJ issued a proposal for decision, which recommends that SPS payment methodology to JD Wind is proper and that JD Wind s complaint be denied. On May 1, 2009 the PUCT issued a final order denying JD Wind s request for relief against SPS. On June 25, 2009, JD Wind filed a petition for review of the final order in Texas District Court. On July 9, 2009, SPS intervened to defend the PUCT s order denying JD Wind s requested relief.

Texas Jurisdictional Fuel Allocation Methodology On May 28, 2009, SPS filed an application to revise the calculation of Texas retail jurisdictional fuel and purchased power expense, effective as of the start of the current fuel reconciliation period, which began in January 2008. SPS has determined that its current method of calculating the monthly amount 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. For the period January 2008 through June 2009, the revised methodology would increase the amount of Texas retail jurisdictional fuel and purchased power cost to be recovered from customers by approximately $5.0 million.

The PUCT has referred this case to the State Office of Administrative Hearings (SOAH) for a contested case hearing. No procedural schedule has yet been established.

Texas Transmission Cost Recovery Factor (TCRF) On June 22, 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. The PUCT implemented rules in late 2007 allowing utilities to request a TCRF in between rate cases for costs of new transmission investment and FERC approved transmission costs. This is SPS first filing under that rule. SPS anticipates the PUCT to issue an order with rates effective by the end of 2009. On July 20, 2009, the PUCT referred this case to the SOAH for a contested case proceeding. A prehearing conference was scheduled for July 30, 2009 to establish a procedural schedule.

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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 is 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.

On March 26, 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.

On May 28, 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.

On July 14, 2009, the NMPRC issued an order approving the stipulation if the parties accept revisions requiring SPS to fund audits of its fuel and purchased power costs and its renewable energy certificate (REC) transactions, with SPS being able to recover the costs of the audits in rates and requiring SPS to provide the NMPRC with notice about certain REC prices. Under the order, the NMPRC s approval becomes effective automatically, without the need for a further NMPRC order, when the parties make their filing accepting the revisions or stating they do not oppose the revisions. On July 15, 2009, SPS filed an amendment to the stipulation that stated SPS acceptance of the revisions and stating that the NMPRC staff and all intervenors accept or do not oppose the revisions. 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 issued an initial decision in the proceeding. The 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. On April 21, 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 NMPRC ALJ has recommended approval of the replacement power agreement. SPS applications before the NMPRC and the PUCT are currently pending.

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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: (1) the ROE should be 9.33 percent; (2) rates should be based on a 12 CP allocator; and (3) the treatment of market based rate contracts in the test-year 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 in proposed revenues that 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.

- **Fuel Clause**: The FERC determined that the method for calculating fuel and purchased energy cost 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 under its precedent. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005 (the refund effective date in the case). The FERC ordered SPS to file a compliance filing calculating its refund obligation and implement the instructions in the order in calculating its FCAC charges going forward from that date. While the order is subject to interpretation with respect to aspects of 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. SPS is reviewing the Order and has not yet determined whether to seek rehearing.

- The FERC also ruled on two other FCA issues. First, it required that wind contracts be evaluated on an individual contract basis rather than in aggregate. Second, the FERC determined that an after-the-fact screen should be applied to all QF purchases to determine if they are economic. While this review will require additional effort, it is not expected that this will result in additional refunds as all of the individual wind contracts as well as the QF purchases are typically economic when compared to market energy prices.

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. In the report, SPS has calculated the base rate refund for the 18-month period to be equal to $6.1 million and the fuel refund to be equal to $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 June 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. SPS, the New Mexico Cooperatives and Cap Rock are now finalizing the settlement documents. The FERC, after receiving comments from interested parties, is expected to consider the proposed settlement. With this settlement, SPS will have settled with all of the complainants in the case.

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. Four New Mexico Cooperatives filed a motion for dismissal and protest in April 2008.

On May 30, 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 CP demand allocator, became effective, subject to refund.

The parties reached a settlement in principle, and an uncontested settlement was filed with the FERC on April 23, 2009. As a result of the settlement, SPS will receive an annual revenue increase of approximately $9.6 million or an overall percentage increase of 3.3 percent. SPS expects the FERC to approve the uncontested settlement.

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,

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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, updated for 2007 actual costs and projected 2008 transmission plant additions, were placed into effect on July 6, 2008, subject to refund.

On July 1, 2009, SPS and the parties notified the ALJ that a settlement in principle had been reached on all issues except the ratemaking and rate design treatment of certain radial transmission lines under the SPP Regional OATT. The settlement terms are not yet public. The radial line issue remains in settlement discussions; if the parties do not reach a settlement in principle by Sept. 4, 2009, SPS expects the issue to be set for litigated proceedings. 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 June 30, 2009, the liability for the cost of remediating these sites was estimated to be $102.9 million, of which $2.5 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.

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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. On Dec. 4, 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. The EPA Remedy Review Board met in November 2008 to consider the remedial approach proposed by the Remedial Project Manager (RPM) for EPA Region 5. On June 12, 2009, the EPA issued its proposed remedial action plan (PRAP). The PRAP will undergo public comment before the EPA makes its final remedy selection in its record of decision, which is currently expected to be issued 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.

On July 23, 2009, NSP-Wisconsin advised the EPA and the 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. NSP-Wisconsin will submit written comments supporting its position by Aug. 17, 2009, the close of the comment period on the PRAP.

In addition to potential liability for remediation, NSP-Wisconsin may also have liability for natural resource damages (NRD) at the Ashland site. NSP-Wisconsin has indicated to the relevant natural resource trustees its interest in engaging in discussions concerning the assessment of natural resources injuries and in proposing various restoration projects in an effort to fully and finally resolve all NRD claims. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Until the EPA and the Wisconsin Department of Natural Resources (WDNR) select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility, 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. 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 work plan 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 MGP-related 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

American Clean Energy and Security Act (ACES) On June 26, 2009, the U.S. House of Representatives passed ACES. Key provisions include a federal cap-and-trade program to reduce GHG emissions by 17 percent by 2020 and 83 percent by 2050 compared to 2005 levels, a national RES, investments in new clean energy technologies and energy efficiency, and mandates for new energy-saving standards. The U.S. Senate has delayed consideration of ACES until September 2009, during which time the bill could change considerably. The ultimate impact of the bill on Xcel Energy therefore remains uncertain.

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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 (NO_x) emissions. The objective of CAIR was to cap emissions of SO_2 and NO_x 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.

As currently written, CAIR has a two-phase compliance schedule, beginning in 2009 for NO_x 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 NO_x 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 NO_x controls in the SPS region are estimated at $4.5 million. For 2009, the estimated NO_x allowance compliance costs are $1.4 million to $2.0 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.

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 NO_x allowances must be surrendered in February 2010. As such, cost estimates are not included at this time for NSP-Minnesota. For 2009, the estimated NO_x allowance costs for NSP-Wisconsin are $1.0 million to $1.6 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. 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. Under the Act, Xcel Energy installed and is operating and maintaining continuous mercury emission monitoring systems at these generating facilities. The information obtained will be used to establish a baseline from which to measure mercury emission reductions.

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, filed on Nov. 3, 2008. In June 2009, NSP-Minnesota received an order from the MPUC closing the docket to correspond with the inclusion of costs in the still pending electric rate case.

The Act required utilities with dry scrubbed units to submit plans for control of mercury for those units by the end of 2007. On Nov. 6, 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

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by Dec. 31, 2009 at Sherco Unit 3 and by Dec. 31, 2010 at A. S. King. On July 16, 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 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.

Voluntary Capacity Upgrade and Emissions Reduction Filing In December 2007, NSP-Minnesota filed a plan with the Minnesota Pollution Control Agency (MPCA) and MPUC for reducing mercury emissions by up to 90 percent at the Sherco Unit 3 and A. S. King plants. Currently, the estimated project costs are approximately $8.5 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco Units 1 and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1 billion. The filing also contains alternatives for the MPUC to consider to add additional capacity and to achieve even lower emissions. If selected, these alternatives could range from $90.8 to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota s investments are subject to MPUC approval of a cost recovery mechanism. The MPCA has issued its assessment that the Sherco Unit 3 and A. S. King plans are appropriate. In light of recent significant changes in the national economy, lower forecast of energy consumption, and new information concerning an emerging technology that may be more cost effective, NSP-Minnesota filed a request with the MPUC to withdraw the plan on Nov. 6, 2008, to allow NSP-Minnesota to reevaluate alternatives. The MPUC granted the withdrawal request on Dec. 9, 2008.

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.

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 SO_2 and NO_x limits in the draft state implementation plan that are equivalent to the reductions made under CAIR.

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 Second Circuit s 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.

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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 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 Sept. 5, 2009. Trial for all cases venued in Nevada will likely be set for late 2009 or early 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. 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.

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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. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

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. No explanation was given for the order. The Court of Appeals has taken the matter under advisement.

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 CO_2 and other GHGs contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence, 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. The matter has now been fully briefed. It is uncertain when the court will render a decision.

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 are required to be filed by September 2009.

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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 and Qwest s reply brief will be due Aug. 7, 2009.

Hoffman vs. Northern States Power Company In March 2006, a purported class action complaint was filed in Minnesota state court, on behalf of NSP-Minnesota s residential customers in Minnesota, North Dakota and South Dakota for alleged breach of a contractual obligation to maintain and inspect the points of connection between NSP-Minnesota s wires and customers homes within the meter box. Plaintiffs claim NSP-Minnesota s alleged breach results in an increased risk of fire and is in violation of tariffs on file with the MPUC. Plaintiffs seek injunctive relief and damages in an amount equal to the value of inspections plaintiffs claim NSP-Minnesota was required to perform over the past six years. In August 2006, NSP-Minnesota filed a motion for dismissal on the pleadings. In November 2006, the court issued an order denying NSP-Minnesota s motion, but later, pursuant to a motion by NSP-Minnesota, certified the issues raised in NSP-Minnesota s original motion for appeal as important and doubtful, and NSP-Minnesota filed an appeal with the Minnesota Court of Appeals. In January 2008, the Minnesota Court of Appeals determined the plaintiffs claims are barred by the filed rate doctrine and remanded the case to the district court for dismissal. Plaintiffs petitioned the Minnesota Supreme Court for discretionary review, and the Supreme Court granted the petition. On April 16, 2009, the Minnesota Supreme Court determined that the filed rate doctrine barred plaintiffs claims for compensatory damages and that under the primary jurisdiction doctrine plaintiffs claims for injunctive relief should be heard by the MPUC. The Supreme Court stated that claims relating to North Dakota and South Dakota residents were not properly before the Court and should therefore be remanded to the District Court for disposition consistent with the Supreme Court s decision.

MGP Insurance Coverage Litigation In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and 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. In November 2007, Ranger and TIG filed a motion to dismiss NSP-Wisconsin s appeal, asserting that NSP-Wisconsin s failure to serve Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company (Harbor), requires dismissal of NSP-Wisconsin s appeal. In February 2008, the Court of Appeals issued an order deferring a decision on the procedural motion filed by Harbor and TIG and referring the motion to the panel assigned to consider the merits of the appeal.

On Jan. 29, 2009, the Wisconsin Supreme Court issued its decision in *Plastics Engineering Co. vs. Liberty Mutual Insurance Co*., adopting an all sums method of allocating damages when an injury spans multiple, successive policy periods.   On June 2, 2009, the Minnesota Court of Appeals heard oral arguments and is expected to issue a decision in early September 2009.

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. The DOE must file its expert report by Oct. 15, 2009, and all discovery must be completed by the end of 2009. Trial is expected to take place in 2010.

Fargo Gas Explosion In September 2008, an explosion occurred at a duplex in Fargo, N.D. The explosion destroyed one side of the duplex and resulted in injuries to some of the residents. Xcel Energy subsequently provided a report to the U.S. Dept. of Transportation Pipeline and Hazardous Materials Safety Administration stating that natural gas migrated into the house and was ignited by an unknown source. Investigators identified a natural gas leak the size of a pinhole located 18 inches underground. The property owners and attorneys representing the injured residents put Xcel Energy on notice of potential claims, and the claims of all residents allegedly injured were resolved following mediation in June 2009. Settlement of these claims will not have a material financial impact on Xcel Energy.

Mallon vs. Xcel Energy Inc. In August 2007, Xcel Energy, PSCo and PSR Investments, Inc. (PSRI) 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, Xcel Energy, PSCo and PSRI 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 PSCo, Xcel Energy and PSRI. In January 2009, the court granted defendant Mallon s motion to amend his answer to, among other things, add a counterclaim for breach of contract and fraud against plaintiffs PSRI, PSCo and Xcel Energy. Xcel Energy believes the counterclaims are without merit and filed a motion to dismiss. The court subsequently denied this motion at this stage of the lawsuit.

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.

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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 has been 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 are 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) has also been 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.

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 s response to the complaint is due in August 2009. 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.

8. Short-Term Borrowings and Other Financing Instruments

Commercial Paper At June 30, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $370.0 million and $330.3 million, respectively. The weighted average interest rates at June 30, 2009 and Dec. 31, 2008 were 1.01 percent and 3.53 percent, respectively. At June 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 June 30, 2009, Xcel Energy and its subsidiaries had no credit facility bank borrowings.

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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 June 30, 2009 and Dec. 31, 2008, Xcel Energy and its utility subsidiaries had money pool loans outstanding of $38.0 million and $104.5 million, respectively. The money pool loans are eliminated upon consolidation. The weighted average interest rates at June 30, 2009 and Dec. 31, 2008, were 0.90 percent and 3.48 percent, respectively.

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.

10. Derivative Instruments

Effective Jan. 1, 2009, Xcel Energy adopted SFAS No. 161, 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 designated as cash flow hedges for accounting purposes.

At June 30, 2009, accumulated other comprehensive income related to interest rate derivatives included $0.6 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest transactions impact earnings.

At June 30, 2009, Xcel Energy had one 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 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 June 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 these 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 six months ended June 30, 2009 and 2008.

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At June 30, 2009, Xcel Energy had $6.1 million of net losses in accumulated other comprehensive income related to utility commodity and vehicle fuel cash flow hedges of which $4.5 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 six months ended June 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:

	June 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	$ 348,654	$ 338,950	$ 374,692	$ 353,531
Commodity derivatives	80,377	55,961	52,968	54,307
Interest rate derivatives		6,494		8,503
Total	$ 429,031	$ 401,405	$ 427,660	$ 416,341

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, 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 June 30,	
(Thousands of Dollars)	**2009**	**2008**
Accumulated other comprehensive loss related to cash flow hedges at April 1	$ (11,913)	$ (7,042)
After-tax net unrealized gains related to derivatives accounted for as hedges	1,270	843
After-tax net realized losses on derivative transactions reclassified into earnings	861	65
Accumulated other comprehensive loss related to cash flow hedges at June 30	$ (9,782)	$ (6,134)

(Thousands of Dollars)	Six Months Ended June 30, 2009	2008
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$ (13,113)	$ (1,416)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	1,160	(4,758)
After-tax net realized losses on derivative transactions reclassified into earnings	2,171	40
Accumulated other comprehensive loss related to cash flow hedges at June 30	$ (9,782)	$ (6,134)

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

(Thousands of Dollars)	June 30, 2009 Fair Value	Counterparty Netting (a)	Derivative Instruments Valuation
Current derivative assets			
Other derivative instruments:			
Trading commodity	$ 21,277	$ (12,826)	$ 8,451
Electric commodity	53,966	1,383	55,349
Natural gas commodity	2,549	161	2,710
Other	200		200
Total current derivative assets	$ 77,992	$ (11,282)	$ 66,710
Noncurrent derivative assets			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	$ 104	$	$ 104
Other derivative instruments:			
Trading commodity	17,726	(4,606)	13,120
Natural gas commodity	231	212	443
	17,957	(4,394)	13,563
Total noncurrent derivative assets	$ 18,061	$ (4,394)	$ 13,667
Current derivative liabilities			
Derivatives designated as cash flow hedges:			
Natural gas commodity	$ 1,659	$	$ 1,659
Vehicle fuel and other commodity	4,785		4,785
	6,444		6,444
Other derivative instruments:			
Interest rate	1,537		1,537
Trading commodity	20,052	(15,221)	4,831
Electric commodity	11,010	1,383	12,393
Natural gas commodity	19,233	161	19,394
	51,832	(13,677)	38,155
Total current derivative liabilities	$ 58,276	$ (13,677)	$ 44,599
Noncurrent derivative liabilities			
Derivatives designated as cash flow hedges:			
Vehicle fuel and other commodity	$ 1,812	$	$ 1,812
Other derivative instruments:			
Interest rate	4,957		4,957
Trading commodity	13,554	(4,610)	8,944
Natural gas commodity	1,930	213	2,143
	20,441	(4,397)	16,044
Total noncurrent derivative liabilities	$ 22,253	$ (4,397)	$ 17,856

(a) FASB Interpretation No. 39 *Offsetting of Amounts Relating to Certain Contracts*, as amended by FASB Staff Position FIN 39-1 *Amendment of FASB Interpretation No. 39*, 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 six months ended June 30, 2009, on other comprehensive income, regulatory assets and liabilities, and income:

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

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

(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 June 30, 2009, commodity derivatives recorded to derivative instruments valuation included derivative contracts with gross notional amounts of approximately 28,496,000 megawatt hours (MwH) of electricity, 54,212,000 MMBtu of natural gas, and 5,170,000 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 utility subsidiaries derivative instruments 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 NSP-Minnesota and PSCo at June 30, 2009, were downgraded below investment grade, contracts underlying $1.0 and $0.8 million of derivative instruments in a liability position, respectively, would have required NSP-Minnesota and PSCo to post collateral or settle the contracts, which would have resulted in payments to applicable counterparties of $1.0 and $0.8 million, respectively. 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 June 30, 2009, would have resulted in the payment of the fair value of the derivative liability to the counterparty of approximately $6.5 million. At June 30, 2009, there was no collateral posted on these specific contracts.

Certain of the utility subsidiaries derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary s ability to fulfill its contractual obligations is reasonably expected to be impaired. As of June 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:

	June 30, 2009		Dec. 31, 2008	
(Thousands of Dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Nuclear decommissioning fund	$ 1,118,593	$ 1,118,593	$ 1,075,294	$ 1,075,294
Other investments	10,027	10,027	9,864	9,864
Long-term debt, including current portion	8,514,389	8,993,576	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 June 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 June 30, 2009 and Dec. 31, 2008, Xcel Energy had issued guarantees of up to $73.0 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 June 30, 2009 and Dec. 31, 2008, was approximately $27.4 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 June 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 *Fair Value Measurements* (SFAS No. 157) for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 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:

	June 30, 2009				
(Thousands of Dollars)	**Level 1**	**Level 2**	**Level 3**	**Counterparty Netting**	**Net Balance**
Assets					
Cash equivalents	$	$ 307,500	$	$	$ 307,500
Nuclear decommissioning fund					
Cash equivalents		20,576			20,576
Debt securities		531,071	86,337		617,408
Equity securities	480,609				480,609
Commodity derivatives		24,788	71,265	(15,676)	80,377
Total	**$** 480,609	**$** 883,935	**$** 157,602	**$** (15,676)	**$** 1,506,470
Liabilities					
Commodity derivatives	$	$ 52,081	$ 21,954	$ (18,074)	$ 55,961
Interest rate derivatives		6,494			6,494
Total	$	$ 58,575	$ 21,954	$ (18,074)	$ 62,455

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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 six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,			
	2009		2008	
(Thousands of Dollars)	Commodity Derivatives, Net	Nuclear Decommissioning Fund	Commodity Derivatives, Net	Nuclear Decommissioning Fund
Balance April 1	$ 3,691	$ 105,552	$ 15,355	$ 97,232
Purchases, issuances, and settlements, net	(863)	(23,314)	(1,710)	13,901
Transfers into Level 3	569			
Gains (losses) recognized in earnings	(2,347)		2,085	
Gains (losses) recognized as regulatory assets and liabilities	48,261	4,099	8,419	(1,717)
Balance June 30	$ 49,311	$ 86,337	$ 24,149	$ 109,416

	Six Months Ended June 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	(1,223)	(28,126)	(4,977)	3,650
Transfers into Level 3	569			
Gains (losses) recognized in earnings	(2,076)		2,036	
Gains (losses) recognized as regulatory assets and liabilities	28,820	5,040	7,624	(2,890)
Balance June 30	$ 49,311	$ 86,337	$ 24,149	$ 109,416

Losses on Level 3 commodity derivatives recognized in earnings for the three and six months ended June 30, 2009, include $0.6 million and $4.4 million of net unrealized gains relating to commodity derivatives held at June 30, 2009. Gains on Level 3 commodity derivatives recognized in earnings for the three and six months ended June 30, 2008, include $1.9 million and $4.4 million of net unrealized gains relating to commodity derivatives held at June 30, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric revenues. Realized and unrealized gains and losses on short-term wholesale activities reflect the impact of regulatory recovery and are deferred as regulatory assets and liabilities. 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. Interest and Other Income (Expenses), Net

Interest and other income (expenses), net, consisted of the following:

(Thousands of Dollars)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Interest income	$ 3,140	$ 4,880	$ 6,066	$ 12,390
Other nonoperating income	2,331	1,844	2,830	3,606
Insurance policy (expenses) income	(2,371)	2,437	(3,343)	1,538
Other nonoperating expenses	(81)		(182)	
Total interest and other income (expenses), net	$ 3,019	$ 9,161	$ 5,371	$ 17,534

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. Commodity trading results are included in the regulated electric segment.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2009					
Operating revenues from external customers	$ 1,733,695	$ 265,884	$ 16,504	$	$ 2,016,083
Intersegment revenues	161	627		(788)	
Total revenues	$ 1,733,856	$ 266,511	$ 16,504	$ (788)	$ 2,016,083
Income (loss) from continuing operations	$ 116,199	$ 11,796	$ 6,391	$ (17,322)	$ 117,064
Three Months Ended June 30, 2008					
Operating revenues from external customers	$ 2,154,383	$ 443,613	$ 17,519	$	$ 2,615,515
Intersegment revenues	296	1,997		(2,293)	
Total revenues	$ 2,154,679	$ 445,610	$ 17,519	$ (2,293)	$ 2,615,515
Income (loss) from continuing operations	$ 106,770	$ 11,872	$ 5,955	$ (19,124)	$ 105,473

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(Thousands of Dollars)		Regulated Electric		Regulated Natural Gas		All Other		Reconciling Eliminations		Consolidated Total
Six Months Ended June 30, 2009										
Operating revenues from external customers	$	3,620,252	$	1,054,560	$	36,813	$		$	4,711,625
Intersegment revenues		418		1,921				(2,339)		
Total revenues	$	3,620,670	$	1,056,481	$	36,813	$	(2,339)	$	4,711,625
Income (loss) from continuing operations	$	237,641	$	72,070	$	14,587	$	(31,416)	$	292,882
Six Months Ended June 30, 2008										
Operating revenues from external customers	$	4,127,697	$	1,477,740	$	38,466	$		$	5,643,903
Intersegment revenues		542		4,623				(5,165)		
Total revenues	$	4,128,239	$	1,482,363	$	38,466	$	(5,165)	$	5,643,903
Income (loss) from continuing operations	$	199,847	$	79,438	$	15,606	$	(35,423)	$	259,468

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 June 30, 2009 and 2008, Xcel Energy had approximately 7.6 million and 8.0 million stock options outstanding, respectively, that were antidilutive and excluded from the earnings per share calculation. For the six months ended June 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 six months ended June 30, 2009 and 2008:

	Three Months Ended June 30, 2009					Three Months Ended June 30, 2008				
(Amounts in thousands, except per share data)		Income	Shares		Per Share Amount		Income	Shares		Per Share Amount
Net income	$	117,107				$	105,572			
Less: Dividend requirements on preferred stock		(1,060)					(1,060)			
Basic earnings per share:										
Earnings available to common shareholders		116,047	456,307	$	0.25		104,512	430,811	$	0.24
Effect of dilutive securities:										
Convertible senior notes							802	4,663		
401(k) equity awards			459					364		
Stock options								30		
Diluted earnings per share:										
Earnings available to common shareholders and assumed conversions	$	116,047	456,766	$	0.25	$	105,314	435,868	$	0.24

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(Amounts in thousands, except per share data)	Six Months Ended June 30, 2009 Income	Shares	Per Share Amount	Six Months Ended June 30, 2008 Income	Shares	Per Share Amount
Net income	$ 291,174			$ 258,690		
Less: Dividend requirements on preferred stock	(2,120)			(2,120)		
Basic earnings per share:						
Earnings available to common shareholders	289,054	455,753	$ 0.63	256,570	430,187	$ 0.60
Effect of dilutive securities:						
Convertible senior notes				1,582	4,663	
401(k) equity awards		609			481	
Stock options					29	
Diluted earnings per share:						
Earnings available to common shareholders and assumed conversions	$ 289,054	456,362	$ 0.63	$ 258,152	435,360	$ 0.59

16. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three Months Ended June 30,			
	2009	2008	2009	2008
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 16,744	$ 14,929	$ 1,057	$ 1,211
Interest cost	43,046	44,677	13,050	12,894
Expected return on plan assets	(64,909)	(68,697)	(5,993)	(8,425)
Amortization of transition obligation			3,726	3,644
Amortization of prior service cost (credit)	6,154	5,166	(711)	(544)
Amortization of net loss	3,299	3,511	4,779	3,031
Net periodic benefit cost (credit)	4,334	(414)	15,908	11,811
(Cost) credits not recognized and additional cost recognized due to the effects of regulation	(959)	1,925	973	973
Net benefit cost recognized for financial reporting	$ 3,375	$ 1,511	$ 16,881	$ 12,784

	Six Months Ended June 30,			
	2009	2008	2009	2008
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 32,730	$ 31,702	$ 2,333	$ 2,675
Interest cost	84,895	85,260	25,206	25,440
Expected return on plan assets	(128,269)	(137,169)	(11,388)	(15,925)
Amortization of transition obligation			7,222	7,288
Amortization of prior service cost (credit)	12,309	10,332	(1,363)	(1,088)
Amortization of net loss	6,228	6,370	9,665	5,749
Net periodic benefit cost (credit)	7,893	(3,505)	31,675	24,139
(Cost) credits not recognized and additional cost recognized due to the effects of regulation	(1,446)	4,517	1,946	1,946
Net benefit cost recognized for financial reporting	$ 6,447	$ 1,012	$ 33,621	$ 26,085

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

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

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 Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended June 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 June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
PSCo	$ 0.13	$ 0.15	$ 0.31	$ 0.37
NSP-Minnesota	0.11	0.11	0.27	0.26
NSP-Wisconsin	0.01	0.01	0.06	0.04
SPS	0.03	0.01	0.06	
Equity earnings of unconsolidated subsidiaries (WYCO)	0.01		0.01	
Regulated utility continuing operations	0.29	0.28	0.71	0.67
Holding company and other costs	(0.04)	(0.04)	(0.07)	(0.08)
Ongoing(a) diluted earnings per share	**0.25**	**0.24**	**0.64**	**0.59**
PSRI			(0.01)	
GAAP diluted earnings per share	**$ 0.25**	**$ 0.24**	**$ 0.63**	**$ 0.59**

(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.

Earnings at PSCo declined by two cents per share for the second quarter and by six cents per share for the six months ending June 30, 2009, largely due to rising costs and relatively flat weather adjusted electric and gas sales margin. In May 2009, the CPUC approved an annual electric rate increase of $112 million and rates went into effect in July 2009.

Earnings at NSP-Minnesota were flat for the second quarter and increased by one cent per share for the six months ending June 30, 2009. In Minnesota, there is a pending rate case with interim rates, subject to refund, which went into effect in January 2009. These interim rates provided incremental revenue and cost recovery, which offset declining sales and rising costs.

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Earnings at NSP-Wisconsin were flat for the second quarter and increased by two cents per share for the six months ending June 30, 2009, largely due to improved fuel recovery and new rates which were effective in January 2009.

Earnings at SPS increased by two cents per share for the second quarter and by six cents per share for the six months ending June 30, 2009, primarily due to electric rate increases in Texas (effective in February 2009), and New Mexico and the 2008 resolution of certain fuel cost allocation issues, which were partially offset by higher purchased capacity costs.

Equity earnings of unconsolidated subsidiaries increased by one cent per share for the second quarter and for the six months ending June 30, 2009, due to Xcel Energy s investment in WYCO, which owns a new gas pipeline in Colorado that began operations in late 2008.

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 June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
GAAP income (loss) by segment				
Regulated electric income continuing operations	$ 123.9	$ 106.8	$ 245.3	$ 199.9
Regulated natural gas income continuing operations	10.2	11.8	70.5	79.4
Other regulated income(a)	0.5	6.3	7.6	16.0
Segment income continuing operations	134.6	124.9	323.4	295.3
Holding company costs and other results(a)	(17.5)	(19.4)	(30.5)	(35.8)
Total income continuing operations	117.1	105.5	292.9	259.5
Discontinued operations		0.1	(1.7)	(0.8)
Total GAAP net income	$ 117.1	$ 105.6	$ 291.2	$ 258.7

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
GAAP earnings (loss) by segment				
Regulated electric continuing operations	$ 0.27	$ 0.25	$ 0.54	$ 0.46
Regulated natural gas continuing operations	0.02	0.02	0.15	0.18
Other regulated income(a)		0.01	0.01	0.03
Segment earnings per share continuing operations	0.29	0.28	0.70	0.67

Holding company costs and other results(a)	(0.04)	(0.04)	(0.07)	(0.08)
Total earnings per share continuing operations	0.25	0.24	0.63	0.59
Discontinued operations				
Total earnings per share continuing operations	$ 0.25	$ 0.24	$ 0.63	$ 0.59

(a) Not a reportable segment. Refer to Segment Results 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 June 30,	Six Months Ended June 30,
2008 GAAP and ongoing(a) diluted earnings per share	**$ 0.24**	**$ 0.59**
Components of change 2009 vs. 2008		
Higher electric margins	0.07	0.18
Higher allowance for funds used during construction equity	0.01	0.02
Lower depreciation and amortization expenses	0.01	
Higher operating and maintenance expenses	(0.02)	(0.04)
Higher conservation and DSM expenses (generally offset in revenue)	(0.02)	(0.03)
Dilution from DRIP, benefit plan and the 2008 common equity issuance	(0.01)	(0.03)
Higher interest expenses	(0.01)	(0.02)
Lower natural gas margins	(0.01)	(0.03)
Other	(0.01)	(0.01)
2009 GAAP diluted earnings per share	**0.25**	**0.63**
PSRI		0.01
2009 ongoing(a) diluted earnings per share	**$ 0.25**	**$ 0.64**

(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 June 30,			Six Months Ended June 30,		
	2009 vs. Normal	2008 vs. Normal	2009 vs. 2008	2009 vs. Normal	2008 vs. Normal	2009 vs. 2008
Retail electric	$ (0.01)	$ (0.02)	$ 0.01	$ (0.01)	$ (0.01)	$
Firm natural gas				(0.01)	0.01	(0.02)
Total	$ (0.01)	$ (0.02)	$ 0.01	$ (0.02)	$	$ (0.02)

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.

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Electric The following tables detail the electric revenues and margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of Dollars)	**2009**	**2008**	**2009**	**2008**
Electric revenues	$ 1,734	$ 2,154	$ 3,620	$ 4,128
Electric fuel and purchased power	(797)	(1,269)	(1,722)	(2,358)
Electric margin	$ 937	$ 885	$ 1,898	$ 1,770

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30, 2009 vs. 2008	Six Months Ended June 30, 2009 vs. 2008
Fuel and purchased power cost recovery	$ (450)	$ (625)
Trading	(26)	(52)
Retail sales decline (excluding weather impact)	(16)	(18)
Retail rate increases (Minnesota interim, Texas, Wisconsin and New Mexico)	43	84
Conservation and DSM revenues (generally offset by O&M expenses)	16	34
Sales mix and demand revenues	8	15
Estimated impact of weather	7	1
Non-fuel riders	6	14
MERP rider	4	10
Transmission revenues	3	6
SPS 2008 fuel cost allocation regulatory accruals		12
Other, net	(15)	11
Total decrease in electric revenue	$ (420)	$ (508)

Electric Margin

(Millions of Dollars)	Three Months Ended June 30, 2009 vs. 2008	Six Months Ended June 30, 2009 vs. 2008
Retail rate increases (Minnesota interim, Texas, Wisconsin and New Mexico)	$ 43	$ 84
Conservation and DSM revenues (generally offset by O&M expenses)	16	34
Sales mix and demand revenues	8	15
Estimated impact of weather	7	1
Non-fuel riders	6	14
Firm wholesale	6	9
MERP rider	4	10
SPS 2008 fuel cost allocation regulatory accruals		12
Retail sales decline (excluding weather impact)	(16)	(18)
Purchased capacity costs	(15)	(33)
NSP-Wisconsin fuel recovery	(2)	7
Other, net	(5)	(7)
Total increase in electric margin	$ 52	$ 128

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:

	Three Months Ended June 30,				Six Months Ended June 30,			
(Millions of Dollars)	**2009**		**2008**		**2009**		**2008**	
Natural gas revenues	$	266	$	444	$	1,055	$	1,478
Cost of natural gas sold and transported		(146)		(320)		(738)		(1,143)
Natural gas margin	$	120	$	124	$	317	$	335

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

Natural Gas Revenues

(Millions of Dollars)	**Three Months Ended June 30, 2009 vs. 2008**		**Six Months Ended June 30, 2009 vs 2008**	
Purchased natural gas adjustment clause recovery	$	(173)	$	(408)
Estimated impact of weather		(3)		(12)
Conservation and DSM revenues (generally offset by O&M expenses)		2		1
Other, net including sales mix/price		(4)		(4)
Total decrease in natural gas revenues	$	(178)	$	(423)

Natural Gas Margin

(Millions of Dollars)	**Three Months Ended June 30, 2009 vs. 2008**		**Six Months Ended June 30, 2009 vs. 2008**	
Estimated impact of weather	$	(3)	$	(12)
Conservation and DSM revenues (generally offset by O&M expenses)		2		1
Other, net		(3)		(7)
Total decrease in natural gas margin	$	(4)	$	(18)

Non-Fuel Operating Expense and Other Items

Other Operating and Maintenance (O&M) Expenses O&M expenses increased by approximately $15.6 million, or 3.4 percent, for the second quarter and approximately $26.5 million, or 2.9 percent for the first six months of 2009, compared with 2008. The following table summarizes the changes in other O&M expenses:

(Millions of Dollars)	**Three Months Ended June 30, 2009 vs. 2008**		**Six Months Ended June 30, 2009 vs. 2008**	
Nuclear outage costs, net of deferral	$	10	$	(1)
Higher employee benefit costs		9		25
Higher nuclear plant operation costs		8		16

Lower consulting costs		(7)		(11)
Lower material costs		(3)		(4)
Other, net		(1)		2
Total increase in other operating and maintenance expenses	$	16	$	27

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 (NRC) requirements.

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Conservation and Demand Side Management (DSM) Program Expenses Conservation and DSM expenses increased approximately $12.2 million, or 41.7 percent for the second quarter of 2009, and by $21.8 million, or 33.7 percent, for the first six 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 Xcel Energy s major jurisdictions or through base rates with tracker mechanisms.

Depreciation and Amortization Depreciation and amortization expenses decreased by approximately $5.4 million, or 2.6 percent, for the second quarter of 2009, and by $2.3 million, or 0.6 percent, for the first six months of 2009, compared with the same periods in 2008. Higher depreciation due to normal system expansion was offset by a decrease in decommissioning amortization as the recovery periods for the Prairie Island and the Monticello plants were both extended. Those recovery periods were approved by the MPUC in June 2009.

Allowance for Funds Used During Construction, Equity and Debt (AFDC) AFDC increased by approximately $4.0 million, or 16.4 percent, for the second quarter of 2009, and by $8.7 million, or 18.1 percent, for the first six 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 by completed in the fourth quarter of 2009, as well as other construction projects.

Interest Charges Interest charges increased by approximately $5.6 million, or 4.2 percent, for the second quarter of 2009, and by $15.2 million, or 5.7 percent, for the first six months of 2009, compared with the same periods in 2008. The increase was primarily the result of increased debt levels to fund new capital investments.

Income Taxes Income tax expense for continuing operations increased by $3.0 million for the second quarter of 2009, compared with 2008. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 33.7 percent for the second quarter of 2009, compared with 34.3 percent for the same period in 2008. The lower effective tax rate for the second quarter of 2009 was primarily due to a decrease in the forecasted annual effective tax rate for 2009 as compared to 2008.

Income tax expense for continuing operations increased by $13.8 million for the first six months of 2009, compared with the first six months of 2008. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 33.6 percent for the first six months of 2009, compared with 33.7 percent for the same period in 2008.

Equity Earnings of Unconsolidated Subsidiaries Equity earnings of unconsolidated subsidiaries increased by $2.8 million for the second quarter of 2009, and by $5.6 million, for the first six 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 gas pipeline, located in Colorado, commencing operations in late 2008.

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;

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- 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.

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.

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. An ALJ ruling is expected in the third quarter of 2009. Pursuant to a 2003 law, once the MPUC has acted on a CON request, 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. Both proceedings are awaiting preparation and filing of environmental impact statements by the respective state and federal agencies. At this time, it is uncertain when ultimate approval of the license extension will occur.

Wind Generation In December 2008, the first NSP-Minnesota owned wind generation plant, the 100 MW Grand Meadow wind farm, went into service. The project was developed through a build-own-transfer arrangement with a large wind energy developer (enXco) at a cost of approximately $210 million. 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. On June 10, 2009, the MPUC issued an order approving investments in the Nobles and Merricourt Wind Projects. NDPSC action is pending.

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. Several parties have filed petitions asking for reconsideration of various decisions in the MPUC order. On July 14, 2009, the MPUC voted to reconsider the decision and modify the conditions in a manner supported by NSP-Minnesota. The modifications clarify that schedules for wind project additions are also to be coordinated with MPUC approvals in resource planning dockets.

As part of CapX 2020, NSP-Minnesota and Great River Energy have filed two route permit applications with the MPUC. On Dec. 29, 2008, the route permit application for the Brookings to Hampton Corner Project was filed. On April 8, 2009, the route permit application for the Monticello to St. Cloud portion of the Fargo Twin Cities project was filed. Route permit applications for the remaining parts of the three projects will be filed in Minnesota later this year. Permit filings will also be made in adjoining states. NSP-Minnesota anticipates the first routing decisions in early 2010.

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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.

In the third quarter of 2009, NSP-Minnesota plans to file a CON application with the MPUC for one or two 161 KV transmission lines in the Rochester, Minn. area to support ongoing development of wind powered generation in southeastern Minnesota. The first proposal consists of an approximately 15 mile long, 161 KV transmission line north of Rochester, and the second, an approximately 30 mile long, 161 KV transmission line southeast of Rochester. The project s estimated cost is $30 million. An MPUC decision is anticipated in 2010.

On May 11, 2009, the city of Taylors Falls, Minn. filed a petition asking the MPUC to amend the route permit issued to NSP-Minnesota in February 2008 for the Chisago/Apple River 115/161 KV upgrade project, alleging the approved route and configuration violate a 2000 settlement agreement signed to resolve a prior transmission routing proceeding. NSP-Minnesota filed reply comments on June 2, 2009, arguing the petition was untimely and procedurally improper. On June 29, 2009, the MPUC issued an order that did not modify the route permit based on the new record information. The MPUC instead required NSP-Minnesota to notify the MPUC within ten days of a decision by the U.S. Army Corps of Engineers (COE) on the permit application to the COE for construction near the St. Croix River. NSP-Minnesota is now attempting to resolve all issues with the city.

NSP-Wisconsin

Bay Front Biomass Gasification On Feb. 23, 2009, NSP-Wisconsin filed an application with the PSCW for a certificate of authority 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 existing coal-fired unit 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 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.

On June 19, 2009 NSP-Wisconsin filed direct testimony and exhibits in support of its application. NSP-Minnesota also made filings in North Dakota and Minnesota to ensure future recovery in rates of the portion of the project costs that will be billed to NSP-Minnesota through the Interchange Agreement.

On July 20, 2009 the PSCW staff and intervenors filed their direct testimony in the case. The PSCW staff testimony is generally supportive of the project. PSCW staff reviewed the application for conformance with applicable statutory requirements and identified five reasons that make it desirable to convert the third Bay Front boiler to biomass: i) additional mercury emission controls for the third boiler are too costly to continue operating this unit as a coal baseload facility; ii) there is pending legislation regarding additional restrictions in greenhouse gas emissions; iii) there is an increasing likelihood of higher renewable energy mandates at the state or federal level; iv) the project has reasonable proximity to adequate fuel sources; and v) the project is less costly than building a new generating facility. PSCW staff s testimony also indicates that

NSP-Wisconsin s plans to incorporate sustainability guidelines into its biomass supply contracts should satisfy environmental concerns regarding biomass harvesting. Lastly, PSCW staff testimony identified a few concerns related to various aspects of the project and requested additional information to supplement NSP-Wisconsin s application.

Two intervenors, RENEW Wisconsin and Cooperative Network, filed testimony in support of the project. RENEW Wisconsin posits that several environmental, economic and energy policy goals are achieved by approving the project. Cooperative Network testifies that its members in northern Wisconsin are poised to fill the role of aggregating, processing and transporting biomass for use in the project.

Two intervenors, Clean Wisconsin and Wisconsin Paper Council (WPC) filed testimony in opposition to the project. Clean Wisconsin believes the ecological impacts of the project have not been adequately addressed and suggested that the PSCW require a comprehensive environmental analysis addressing their concerns before the project is approved. The WPC argues that i) NSP-Wisconsin has under-estimated the price and over-estimated the available supply of biomass fuel; ii) there is not enough biomass for both the Bay Front project and other planned and existing uses of biomass, which will damage an already struggling forest products industry in Wisconsin; iii) the price increase resulting from NSP-Wisconsin s pressure on biomass supplies will drive up customer rates and; iv) a bio-refinery project proposed by one of WPC s members is a more efficient use of available biomass.

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NSP-Wisconsin is expected to file rebuttal testimony addressing various issues raised by the PSCW staff and the intervenors. The hearing in the case is scheduled for Aug. 12, 2009.

PSCo

PSCo Resource Plan PSCo estimates it will purchase approximately 35 to 45 percent of its total electric system energy needs for 2009 under long-term contracts and generate the remainder with PSCo-owned resources. 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 (RAP) 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 expects to file its bid evaluation report with the CPUC in August 2010.

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. The CPUC issued its decision on June 26, 2009. Initially, the case will follow a 180-day schedule, and an initial decision is expected to be issued by Nov. 10, 2009. However, the case could shift to a 210-day schedule depending on the outcome of a motion filed by one of the parties contesting PSCo s ability to classify this project under Senate Bill 100. Evidentiary hearings are expected to begin on Sept. 21, 2009. Pole Canyon, a transmission company that is in the process of purchasing right-of-way to construct a transmission line that may be in proximity to the proposed Calumet-Comanche line was permitted to intervene.**

SPS

San Luis Valley-Calumet-Comanche Transmission Project PSCo and Tri-State Generation and Transmission Ass

New Mexico Energy Efficiency Disincentive Rulemaking During the last legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. The NMPRC is currently conducting a rulemaking proceeding to update the energy efficiency rule, consistent with the legislative changes. The NMPRC held an evidentiary hearing on the rule on June 26, 2009. It is likely that the NMPRC will act on the proposed rule late in the third quarter or early in the fourth quarter of 2009.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy s utility subsidiaries, including enforcement of North American Electric Reliability Corporation (NERC) mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy s utility activities, including regulation of retail rates and environmental mattersSee 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.

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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. The audit report is subject to further WECC procedures. Xcel Energy is uncertain if the WECC audit report will result in financial penalties being imposed on PSCo.

Compliance with NERC Protective Maintenance Standards

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. Xcel Energy expects that penalties may be assessed by certain of the NERC regional entities in conjunction with some of the self-reports. The penalties are not expected to be material.

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 Sept. 18, 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.

Environmental, Legal and Other Matters

San Luis Valley-Calumet-Comanche Transmission Project PSCo and Tri-State Generation and Transmission Ass

San Luis Valley-Calumet-Comanche Transmission Project	PSCo and Tri-State Generation and Transmission Ass

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 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

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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. Also, as discussed further in the Liquidity and Capital Resources section, the current state of the financial markets may negatively impact Xcel Energy s ability to obtain debt and equity financing under favorable terms.

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

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

The fair value of the commodity trading contracts at June 30 were as follows:

	Six Months Ended June 30,	
(Thousands of Dollars)	**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	(13,144)	(3,770)
Commodity trading contract additions and changes during period	14,372	1,664
Fair value of commodity trading net contract assets outstanding at June 30	$ 5,397	$ 4,209

At June 30, 2009, the fair values by source for the commodity trading net asset (liability) balances were as follows:

		Futures / Forwards				
(Thousands of Dollars)	**Source of Fair Value**	**Maturity Less Than 1 Year**	**Maturity 1 to 3 Years**	**Maturity 4 to 5 Years**	**Maturity Greater Than 5 Years**	**Total Futures/ Forwards Fair Value**
NSP-Minnesota	1	$ 484	$ 950	$	$	$ 1,434
	2	230	1,180	351		1,761
PSCo	1	(1,774)	807			(967)
	2	2,287	446	438		3,171
		$ 1,227	$ 3,383	$ 789	$	$ 5,399

		Options				
(Thousands of Dollars)	**Source of Fair Value**	**Maturity Less Than 1 Year**	**Maturity 1 to 3 Years**	**Maturity 4 to 5 Years**	**Maturity Greater Than 5 Years**	**Total Options Fair Value**

NSP-Minnesota	2	$	(2)	$	$	$	$ (2)
		$	(2)	$	$	$	$ (2)

(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.

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Normal purchases and sales transactions, as defined by SFAS No. 133, 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 June 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 $0.9 million, whereas a 10 percent decrease would increase pretax income from continuing operations by approximately $0.9 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:

	Period Ended June 30, 2009	Change from Period Ended March 31, 2009	VaR Limit	Average	High	Low
Commodity Trading(a)	$ 0.63	$ (1.18)	$ 5.00	$ 0.50	$ 1.73	$ 0.14

(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.

San Luis Valley-Calumet-Comanche Transmission Project	PSCo and Tri-State Generation and Transmission Ass

At June 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 $4.1 million annually, or approximately $1.0 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 June 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 by a counterparty of 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.

San Luis Valley-Calumet-Comanche Transmission Project	PSCo and Tri-State Generation and Transmission Ass

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.

At June 30, 2009, a 10 percent increase in prices would have resulted in a net decrease in commodity derivative assets of $4.4 million, while a decrease of 10 percent would have resulted in a commodity derivative assets increase of $9.1 million.

Fair Value Measurements

Xcel Energy adopted SFAS No. 157 on Jan. 1, 2008. SFAS No. 157 establishes a hierarchy for inputs used in measuring fair value, and requires that the most observable inputs available be used for fair value measurements. Note 12 to the consolidated financial statements describes the SFAS No. 157 fair value hierarchy, and discloses the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

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Commodity Derivatives Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty s ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was immaterial to the fair value of commodity derivative assets at June 30, 2009. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for short-term wholesale instruments are deferred as regulatory assets and liabilities, reflecting the impact of regulatory recovery.

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 June 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 35 percent of total assets and liabilities, respectively, measured at fair value at June 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 $54.1 million and $9.2 million of estimated fair values, respectively, for FTRs held at June 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 $17.2 million and $12.7 million of estimated fair values, respectively, for commodity forwards and options held at June 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 $86.3 million in the nuclear decommissioning fund at June 30, 2009 (approximately 6 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

	Six Months Ended June 30,	
(Millions of Dollars)	**2009**	**2008**
Cash provided by (used in) operating activities		

Continuing operations	$	1,129	$	824
Discontinued operations		(3)		(21)
Total	$	1,126	$	803

Cash Flows

Cash provided by operating activities for continuing operations increased by $305 million for the first six months of 2009, compared with the 2008. This increase was due to the improvements in working capital activity.

	Six Months Ended June 30,			
(Millions of Dollars)		**2009**		**2008**
Cash used in investing activities	$	(934)	$	(1,065)

Cash used in investing activities for continuing operations decreased by $131 million for the first six months of 2009, compared with the first six months of 2008. The decrease was due to reduced capital expenditures as well as reduced investment in the WYCO pipeline and storage project.

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(Millions of Dollars)	Six Months Ended June 30, 2009	2008
Cash (used in) provided by financing activities	$ (61)	$ 278

Cash used in financing activities for continuing operations increased by $339 million for the first six months of 2009, compared with 2008. The increase is primarily due to fewer proceeds from the issuances of long-term debt in the first six months of 2009, as well as repayment of long-term debt issued in prior periods.

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.

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 is reviewing 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. No decisions have been reached by Xcel Energy regarding the application for such funds.

American Clean Energy and Security Act The U.S. House of Representatives recently passed ACES. One provision of significance to the electric utility industry requires the regulation of all derivative and swap transactions. As passed by the House, the 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.

Short-Term Investments Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At June 30, 2009, approximately $332 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.

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The borrowings or loans outstanding at June 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	38	250
PSCo	(38)	250
SPS		100

Credit Facilities As of July 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	$ 5.8	$ 476.4	$ 0.4	$ 476.8	December 2011
PSCo	675.1	4.6	670.5	11.2	681.7	December 2011
SPS	247.9	10.0	237.9	35.2	273.1	December 2011
Xcel Energy Holding Company	771.6					