

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)

**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

**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

(State or other jurisdiction of incorporation or organization)

41-0448030

(I.R.S. Employer Identification No.)

**414 Nicollet Mall
Minneapolis, Minnesota**

55401

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(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. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

| | |
|---|--|
| Large accelerated filer <input checked="" type="checkbox"/> | Accelerated filer <input type="checkbox"/> |
| Non-accelerated filer <input type="checkbox"/> | Smaller Reporting company <input type="checkbox"/> |

(Do not check if 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 No

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

| Class | Outstanding at July 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).

Table of Contents**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, | | Six Months Ended June 30, | |
|--|------------------------------------|------------------|----------------------------------|------------------|
| | 2009 | 2008 | 2009 | 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 |

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| | | | | | | | | |
|--|----|---------|----|---------|----|---------|----|---------|
| 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)

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| | 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)

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| | 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 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)

| | Shares | Common Stock Issued Par Value | Additional Paid In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Common 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 |

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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)

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| | Common Stock Issued | | | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Common Stockholders' Equity |
|--|---------------------|--------------|----------------------------|-------------------|---|-----------------------------------|
| | Shares | Par Value | Additional Paid In Capital | | | |
| 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

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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,

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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

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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.

Table of Contents**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 |

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| | | | | |
|---|----|--------|----|--------|
| 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 |

Table of Contents**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

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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.

On May 26, 2009, parties filed surrebuttal testimony. The OES revised its revenue deficiency to approximately \$92 million.

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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.

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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

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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 (SO₂) and nitrogen oxide (NO_x) emissions. The objective of CAIR was to cap emissions of SO₂ 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 SO₂, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO₂ 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 SO₂ 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 SO₂, NO_x 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 NO_x 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 NO_x 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

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completed their BART determination and proposed SO₂ 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.

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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 (CO₂) 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 CO₂ emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO₂ emitted by each company is a public nuisance 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 CO₂ 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 CO₂ 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' CO₂ 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 CO₂ 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

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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.

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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

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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

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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:

| (Thousands of Dollars) | June 30, 2009 | | Dec. 31, 2008 | |
|--------------------------------------|---|--|---|--|
| | 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:

| (Thousands of Dollars) | Three Months Ended June 30, | |
|---|-----------------------------|------------|
| | 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) |

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| (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) | Fair Value | June 30, 2009 | |
|---|------------|-----------------------------|--|
| | | 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) | Fair Value Changes Recognized During the Period in: | | Three Months Ended June 30, 2009 Pre-Tax Amounts Reclassified into Income | | Pre-Tax Gains Recognized During the Period in Income |
|---|--|---|---|---|---|
| | Other Comprehensive Income (Loss) | Regulatory Assets and Liabilities | Other Comprehensive Income | Regulatory Assets and Liabilities | |
| 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 | | | | | |