XCEL ENERGY INC
Form 10-Q
May 02, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2008

OR

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

For the transition period from to

Commission File Number: 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

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

Registrant s telephone number, including area code **(612) 330-5500**

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

Indicate by check mark whether the registrant 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. (Check one): x Large accelerated filer o Accelerated filer o Non-accelerated filer o Smaller Reporting Company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
o Yes x No

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

Class	**Outstanding at April 25, 2008**
Common Stock, $2.50 par value	430,857,162 shares

TABLE OF CONTENTS

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(Thousands of Dollars, Except Per Share Data)	Three Months Ended March 31, 2008		Three Months Ended March 31, 2007	
Operating revenues				
Electric utility	$	1,973,314	$	1,815,803
Natural gas utility		1,034,127		927,422
Other		20,947		20,437
Total operating revenues		3,028,388		2,763,662
Operating expenses				
Electric fuel and purchased power utility		1,088,080		979,571
Cost of natural gas sold and transported utility		823,127		740,782
Cost of sales other		5,453		6,025
Other operating and maintenance expenses		482,909		467,567
Depreciation and amortization		219,288		213,413
Taxes (other than income taxes)		79,413		78,176
Total operating expenses		2,698,270		2,485,534
Operating income		330,118		278,128
Interest and other income, net		8,884		816
Allowance for funds used during construction equity		14,220		7,576
Interest charges and financing costs				
Interest charges includes other financing costs of $4,991 and $6,271, respectively		132,171		127,303
Allowance for funds used during construction debt		(9,527)		(7,206)
Total interest charges and financing costs		122,644		120,097
Income from continuing operations before income taxes		230,578		166,423
Income taxes		76,584		47,909
Income from continuing operations		153,994		118,514
Income (loss) from discontinued operations, net of tax		(877)		1,197
Net income		153,117		119,711
Dividend requirements on preferred stock		1,060		1,060
Earnings available to common shareholders	$	152,057	$	118,651
Weighted average common shares outstanding (thousands)				
Basic		429,563		408,003
Diluted		434,853		432,054
Earnings per share basic				
Income from continuing operations	$	0.35	$	0.29
Discontinued operations				

Earnings per share basic	$	0.35	$	0.29
Earnings per share diluted				
Income from continuing operations	$	0.35	$	0.28
Discontinued operations				
Earnings per share diluted	$	0.35	$	0.28
Cash dividends declared per common share	$	0.23	$	0.22

See Notes to Consolidated Financial Statements

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

(Thousands of Dollars)

	Three Months Ended March 31, 2008	2007
Operating activities		
Net income	$ 153,117	$ 119,711
Remove loss (income) from discontinued operations	877	(1,197)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	226,271	222,733
Nuclear fuel amortization	13,388	11,554
Deferred income taxes	87,361	43,060
Amortization of investment tax credits	(1,948)	(2,427)
Allowance for equity funds used during construction	(14,220)	(7,576)
Undistributed equity in earnings of unconsolidated affiliates	(510)	(695)
Share-based compensation expense	5,774	4,469
Net realized and unrealized hedging and derivative transactions	22,719	41,763
Changes in operating assets and liabilities:		
Accounts receivable	(11,920)	(57,237)
Accrued unbilled revenues	138,410	(6,542)
Inventories	106,477	118,475
Recoverable purchased natural gas and electric energy costs	(78,192)	179,028
Other current assets	7,053	8,296
Accounts payable	(1,692)	(147,135)
Net regulatory assets and liabilities	11,195	(7,620)
Other current liabilities	(65,915)	82,007
Change in other noncurrent assets	(24,359)	(16,881)
Change in other noncurrent liabilities	1,370	(621)
Operating cash flows provided by (used in) discontinued operations	(25,774)	16,201
Net cash provided by operating activities	549,482	599,366
Investing activities		
Utility capital/construction expenditures	(489,775)	(482,410)
Allowance for equity funds used during construction	14,220	7,576
Purchase of investments in external decommissioning fund	(227,987)	(149,841)
Proceeds from the sale of investments in external decommissioning fund	217,139	138,993
Nonregulated capital expenditures and asset acquisitions	(124)	(135)
Investment in WYCO	(23,026)	
Change in restricted cash	757	2,381
Other investments	519	4,959
Net cash used in investing activities	(508,277)	(478,477)
Financing activities		
Proceeds from (repayment of) short-term borrowings net	(710,643)	108,200
Proceeds from issuance of long-term debt	893,021	
Repayment of long-term debt, including reacquisition premiums	(972)	(101,208)
Early participation payments on debt exchange		(4,859)
Proceeds from issuance of common stock	1,564	4,509
Dividends paid	(99,679)	(91,683)
Net cash provided by (used in) financing activities	83,291	(85,041)
Net increase in cash and cash equivalents	124,496	35,848

Net increase (decrease) in cash and cash equivalents discontinued operations		225		(8,303)
Cash and cash equivalents at beginning of year		51,120		37,458
Cash and cash equivalents at end of quarter	$	175,841	$	65,003
Supplemental disclosure of cash flow information				
Cash paid for interest (net of amounts capitalized)	$	123,368	$	110,606
Cash paid (received) for income taxes (net of refunds received)		(1,092)		4,230
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	29,119	$	50,162
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	34,578	$	30,600

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	March 31, 2008	Dec. 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 175,841	$ 51,120
Accounts receivable, net	963,500	951,580
Accrued unbilled revenues	593,549	731,959
Inventories	425,133	531,610
Recoverable purchased natural gas and electric energy costs	151,607	73,415
Derivative instruments valuation	81,364	94,554
Prepayments and other	172,332	244,134
Current assets held for sale and related to discontinued operations	124,427	128,821
Total current assets	2,687,753	2,807,193
Property, plant and equipment, net	16,955,142	16,675,689
Other assets:		
Nuclear decommissioning fund and other investments	1,312,843	1,372,098
Regulatory assets	1,115,894	1,115,443
Prepaid pension asset	579,223	568,055
Derivative instruments valuation	369,609	383,861
Other	196,320	142,078
Noncurrent assets held for sale and related to discontinued operations	141,836	120,310
Total other assets	3,715,725	3,701,845
Total assets	$ 23,358,620	$ 23,184,727
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 741,571	$ 637,535
Short-term debt	377,917	1,088,560
Accounts payable	1,064,160	1,079,345
Taxes accrued	264,275	240,443
Dividends payable	100,079	99,682
Derivative instruments valuation	46,497	58,811
Other	326,533	419,209
Current liabilities held for sale and related to discontinued operations	10,106	17,539
Total current liabilities	2,931,138	3,641,124
Deferred credits and other liabilities:		
Deferred income taxes	2,560,544	2,553,526
Deferred investment tax credits	110,966	112,914
Asset retirement obligations	1,333,715	1,315,144
Regulatory liabilities	1,399,544	1,389,987
Pension and employee benefit obligations	566,132	576,426
Derivative instruments valuation	371,300	384,419
Customer advances	312,208	305,239
Other	150,998	137,422
Noncurrent liabilities held for sale and related to discontinued operations	20,277	20,384
Total deferred credits and other liabilities	6,825,684	6,795,461
Commitments and contingent liabilities		
Capitalization:		

Long-term debt		7,139,770		6,342,160
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: March 31, 2008 430,512,282; Dec. 31, 2007 428,782,700		6,357,048		6,301,002
Total liabilities and equity	$	23,358,620	$	23,184,727

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY
AND COMPREHENSIVE INCOME

(UNAUDITED)
(Thousands of Dollars)

	Common Stock Issued Shares	Common Stock Issued Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
Three months ended March 31, 2008 and 2007						
Balance at Dec. 31, 2006	407,297	$ 1,018,242	$ 4,043,657	$ 771,249	$ (16,326)	$ 5,816,822
FIN 48 adoption				2,207		2,207
Net income				119,711		119,711
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $125					487	487
Net derivative instrument fair value changes during the period, net of tax of $(1,888)					(800)	(800)
Unrealized gain - marketable securities, net of tax of $2					4	4
Comprehensive income for the period						119,402
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(90,959)		(90,959)
Issuances of common stock	1,564	3,910	12,262			16,172
Share-based compensation			5,667			5,667
Balance at March 31, 2007	408,861	$ 1,022,152	$ 4,061,586	$ 801,148	$ (16,635)	$ 5,868,251
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				153,117		153,117
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $635					(189)	(189)
Net derivative instrument fair value changes during the period, net of tax of $(1,790)					(5,626)	(5,626)
Comprehensive income for the period						147,302
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(99,016)		(99,016)

Issuances of common stock	1,729		4,324		52					4,376
Share-based compensation					6,084					6,084
Balance at March 31, 2008	430,512	$	1,076,281	$	4,293,053	$	1,015,317	$	(27,603)	$ 6,357,048

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of March 31, 2008, and Dec. 31, 2007; the results of its operations and changes in stockholders equity for the three months ended March 31, 2008 and 2007; and its cash flows for the three months ended March 31, 2008 and 2007. Due to the seasonality of Xcel Energy s electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results.

1. 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, 2007, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Fair Value Measurements Xcel Energy presents interest rate derivatives, commodity derivatives, and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. For interest rate derivatives, broker quotes are used to establish fair value. For commodity derivatives, the most observable inputs available are used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use broker quotes for identical or similar contracts, or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data, broker quotes and market inputs are utilized to estimate fair value for each class of security.

2. Recently Issued Accounting Pronouncements

Statement of Financial Accounting Standards (SFAS) No. 157 Fair Value Measurements (SFAS No. 157) In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007.

In February 2008, the FASB issued *Effective Date of FASB Statement No. 157* (FASB Statement of Position (FSP) No. 157-2 (FSP No. 157-2)). FSP No. 157-2 delays the effective date of SFAS No. 157 until fiscal years beginning after Nov. 15, 2008, for fair value measurements of non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in an entity s financial statements on a recurring basis (at least annually).

As of Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for all assets and liabilities measured at fair value except for non-financial assets and non-financial liabilities measured at fair value on a non-recurring basis, as permitted by FSP No. 157-2. The adoption did not have a material impact on its consolidated financial statements. For additional discussion and SFAS No. 157 required disclosures see Note 11 to the consolidated financial statements.

The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159) In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement is effective for fiscal years beginning after Nov. 15, 2007, effective Jan. 1, 2008. Xcel Energy adopted SFAS No. 159 and the adoption did not have a material impact on its consolidated financial statements.

Business Combinations (SFAS No. 141 (revised 2007)) In December 2007, the FASB issued SFAS No. 141R, 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. 141R 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 will evaluate the impact of SFAS No. 141R on its consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

Noncontrolling Interests in Consolidated Financial Statements, an Amendment of Accounting Research Bulletin (ARB) No. 51 (SFAS No. 160) In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent s equity; the amount of consolidated net income attributable to the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently. This statement is effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy is evaluating the impact of SFAS No. 160 on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities (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 of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008, with early application encouraged. Xcel Energy is currently evaluating the impact of adoption of SFAS No. 161.

Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements (Emerging Issues Task Force (EITF) Issue No. 06-4) In June 2006, the EITF reached a consensus on EITF No. 06-4, which provides guidance on the recognition of a liability and related compensation costs for endorsement split-dollar life insurance policies that provide a benefit to an employee that extends to postretirement periods. Therefore, this EITF would not apply to a split-dollar life insurance arrangement that provides a specified benefit to an employee that is limited to the employee s active service period with an employer. EITF No. 06-4 is effective for fiscal years beginning after Dec. 15, 2007, with earlier application permitted. Upon adoption of EITF 06-4 on Jan. 1, 2008, Xcel Energy recorded a liability of $1.6 million, net of tax, as a reduction of retained earnings. Thereafter, changes in the liability will be reflected in operating results.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11) In June 2007, the EITF reached a consensus on EITF No. 06-11, which states that an entity should recognize a realized tax benefit associated with dividends on nonvested equity shares and nonvested equity share units charged to retained earnings as an increase in additional paid in capital. The amount recognized in additional paid in capital should be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF No. 06-11 should be applied prospectively to income tax benefits of dividends on equity-classified share-based payment awards that are declared in fiscal years beginning after Dec. 15, 2007. The adoption of EITF No. 06-11 did not have a material impact on Xcel Energy s consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	**March 31, 2008**	**Dec. 31, 2007**
Accounts receivable, net:		
Accounts receivable	$ 1,011,870	$ 1,000,981
Less allowance for bad debts	(48,370)	(49,401)

	$	963,500	$	951,580
Inventories:				
Materials and supplies	$	157,294	$	152,770
Fuel		157,410		142,764
Natural gas		110,429		236,076
	$	425,133	$	531,610

(Thousands of Dollars)	March 31, 2008	Dec. 31, 2007
Property, plant and equipment, net:		
Electric utility plant	$ 20,470,908	$ 20,313,313
Natural gas utility plant	2,969,077	2,946,455
Common utility and other property	1,481,246	1,475,325
Construction work in progress	2,005,856	1,810,664
Total property, plant and equipment	26,927,087	26,545,757
Less accumulated depreciation	(10,200,128)	(10,049,927)
Nuclear fuel	1,532,941	1,471,229
Less accumulated amortization	(1,304,758)	(1,291,370)
	$ 16,955,142	$ 16,675,689

4. Discontinued Operations

A summary of the subsidiaries presented as discontinued operations is discussed below. Results of operations for divested businesses are reported, for all periods presented, as discontinued operations. In addition, the remaining assets and liabilities related to the businesses divested or discontinued have been reclassified to assets and liabilities 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, originally from discontinued operations, that will be deductible in future years.

Nonregulated Subsidiaries

Seren Innovations Inc., NRG Energy, Inc., e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all sold in 2006 or earlier, continue to have activity and balances reflected on Xcel Energy s financial statements as reported in the tables below.

Summarized Financial Results of Discontinued Operations

(Thousands of Dollars)	2008	2007
Three months ended March 31,		
Operating revenues	$	$ 36
Operating expense, interest and other income, net	31	(233)
Pretax income (loss) from discontinued operations	(31)	269
Income tax expense (benefit)	846	(928)
Net income (loss) from discontinued operations	$ (877)	$ 1,197

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

(Thousands of Dollars)	March 31, 2008	Dec. 31, 2007
Cash	$ 7,017	$ 6,792
Accounts receivable, net	771	913

Deferred income tax benefits		101,256		118,919
Other current assets		15,383		2,197
Current assets related to discontinued operations	$	124,427	$	128,821
Deferred income tax benefits	$	118,469	$	97,284
Other noncurrent assets		23,367		23,026
Noncurrent assets related to discontinued operations	$	141,836	$	120,310
Accounts payable	$	1,033	$	1,060
Other current liabilities		9,073		16,479
Current liabilities related to discontinued operations	$	10,106	$	17,539
Other noncurrent liabilities	$	20,277	$	20,384
Noncurrent liabilities related to discontinued operations	$	20,277	$	20,384

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.

In the first quarter of 2008, the 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, 2008.

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 audit through tax year 2005. No material adjustments were proposed for these state audits. As of March 31, 2008, 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: Colorado-2003, Minnesota-2003, Texas-2003 and Wisconsin-2002.

The amount of unrecognized tax benefits reported in continuing operations was $26.3 million on Dec. 31, 2007, and $26.1 million on March 31, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $4.3 million on Dec. 31, 2007 and $4.3 million on March 31, 2008. These unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss and tax credit carryovers reported in continuing operations of $7.8 million on Dec. 31, 2007 and $8.8 million on March 31, 2008 and net operating loss and tax credit carryovers reported in discontinued operations of $17.8 million on Dec. 31, 2007 and $18.3 million on March 31, 2008.

The unrecognized tax benefit balance reported in continuing operations included $9.8 million and $7.9 million of tax positions on Dec. 31, 2007 and March 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 $16.5 million and $18.2 million of tax positions on Dec. 31, 2007 and March 31, 2008, respectively, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The decrease in the unrecognized tax benefit balance reported in continuing operations of $0.2 million from Dec. 31, 2007 to March 31, 2008, was due to the resolution of certain federal and state 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 when the IRS and state audits resume. However, at this time, 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 net operating loss and tax credit carryovers. The amount of interest income related to unrecognized tax benefits reported within interest charges in continuing operations in the first quarter of 2008 was $1.2 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $5.8 million on Dec. 31, 2007 and $4.6 million on March 31, 2008. The amount of interest income related to unrecognized tax benefits reported within interest charges in discontinued operations in the first quarter of 2008 was $0.2 million. The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $0.5 million on Dec. 31, 2007 and $0.7 million on March 31, 2008.

No amounts were accrued for penalties in the first quarter of 2008. The liability for penalties related to unrecognized tax benefits reported in continuing operations was $1.0 million on Dec. 31, 2007 and March 31, 2008.

The effective tax rate for continuing operations was 33.2 percent for the first quarter of 2008, compared with 28.8 percent for the same period in 2007. The higher effective tax rate for first quarter 2008 was primarily due to an increase in the forecasted annual effective tax rate for 2008, compared with 2007, largely as a result of PSR Investments Inc. (PSRI) terminating the Corporate Owned Life Insurance (COLI) program in 2007.

6. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 14 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference. The following include unresolved proceedings that are material to Xcel Energy s financial position.

NSP-Minnesota

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

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider In November 2006, the MPUC approved a TCR rider pursuant to 2005 legislation. The TCR mechanism allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases.

- In August 2007, NSP-Minnesota filed for approval of recovery of $19.7 million in Minnesota retail electric rates in 2008 under the TCR tariff.
- In December 2007, NSP-Minnesota filed adjustments to these TCR rate factors and implemented adjustment factors set to recover $18.5 million beginning Jan. 1, 2008. In March 2008, the MPUC issued an order approving the 2008 cost recovery (as modified), but requiring certain procedural changes for future TCR filings if costs are disputed. NSP-Minnesota filed the required compliance filing in April 2008.

Renewable Energy Standard (RES) Rider In June 2007, NSP-Minnesota filed an application for a new rate rider to recover the costs associated with utility-owned projects implemented in compliance with the RES adopted by the 2007 Minnesota legislature. The MPUC approved the RES Rider at its March 6, 2008, hearing, and it was implemented on April 1, 2008. Under the rider, NSP-Minnesota could recover up to approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100-megawatt (MW) wind project proposed by NSP-Minnesota, subject to true-up.

Annual Automatic Adjustment Report for 2007 In September 2007, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2006 through June 30, 2007, which is the basis for the MPUC review of charges that flow through the fuel clause adjustment (FCA) and purchased gas adjustment (PGA) mechanisms. During that time period, $1.2 billion in fuel and purchased energy costs, including $384 million of Midwest Independent Transmission System Operator, Inc. (MISO) charges were recovered from electric customers through the FCA. In addition, approximately $590 million of purchased natural gas and transportation costs were recovered through the PGA. The 2007 annual automatic adjustment reports are pending comments and MPUC action. The Minnesota Office of Energy Security (OES, formerly the Minnesota Department of Commerce) is expected to submit its reports to the MPUC by June 14, 2008.

Other

MISO Day 2 Market Cost Recovery In December 2006, the MPUC issued an order ruling that NSP-Minnesota may recover all MISO Day 2 costs, except Schedules 16 and 17 administrative charges, through its fuel clause adjustment (FCA) effective April 1, 2005.

In April 2007, the Minnesota Office of Attorney General (MOAG) filed an appeal of the MPUC order to the Minnesota Court of Appeals (Court) challenging the MPUC s decision to allow FCA recovery of these MISO charges. NSP-Minnesota and the other affected utilities intervened in the appeal and filed briefs urging the court to uphold the MPUC order. On April 15, 2008, the Court issued an opinion affirming the MPUC order.

Nuclear Refueling Outage Costs In November 2007, NSP-Minnesota filed a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request seeks approval to amortize refueling outage costs over the period between refueling outages to better match revenue and expenses. This request, if approved, would reduce 2008 expenses for NSP-Minnesota jurisdiction by approximately $25 million due to deferral and amortization over an 18-month period versus expensed as incurred. In March 2008, the OES issued comments indicating it did not object to adoption of the proposal, subject to conditions. The MOAG filed comments opposing implementation of this change outside of a rate case. Reply comments are expected to be filed in early May, and MPUC action is pending.

Pending Regulatory Proceedings North Dakota Public Service Commission (NDPSC) and South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota North Dakota Electric Rate Case In December 2007, NSP-Minnesota filed a request with the NDPSC to increase North Dakota retail electric rates by $20.5 million, or about 14 percent. The request was based on an 11.50 percent return on equity (ROE), an equity ratio of 51.77 percent, and a rate base of approximately $242 million. Interim rates of $17.2 million became effective in February 2008. NSP-Minnesota and the NDPSC staff reached a stipulation settlement in the rate case in which both parties recommended an ROE of 10.75 percent, with a sharing mechanism for earnings above

10.75 percent. This stipulation settlement is subject to approval by the NDPSC. Hearings are expected to be held in late June, and final rates are expected to be effective Oct. 1, 2008. The procedural schedule is as follows:

• Intervenor testimony	May 9, 2008
• Rebuttal testimony	June 13, 2008
• Hearings	June-July, 2008
• Order issued	Aug. 13, 2008

Nuclear Refueling Outage Costs In late 2007, NSP-Minnesota filed with both the NDPSC and SDPUC a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request is comparable to that filed with the MPUC. In February 2008, the NDPSC approved the request, indicating that appropriate cost recovery levels would be determined in the pending electric rate case. The SDPUC has not acted on the petition.

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

FERC Transmission Rate Case The electric production and transmission system of NSP-Minnesota is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System. In September 2007, Xcel Energy and MISO filed proposed changes to the MISO Transmission and Energy Markets Tariff (TEMT) to establish a revised formula transmission rate for the integrated NSP System. The rate filing would establish the transmission service rates for the NSP System based on annual forward looking (rather than historic) transmission costs; provide more current recovery of NSP System transmission investments and allow recovery of certain transmission incentives authorized by various FERC rules. A forward looking formula rate with a return on construction work in progress for major projects will facilitate the financing and construction of the new transmission facilities while providing a current return on invested capital for the portion of the investment subject to FERC rate jurisdiction. In December 2007, the FERC issued an order accepting the rate change effective Jan. 1, 2008, subject to Xcel Energy and MISO making certain changes to the procedures for pre-filing notice of the annual formula rate changes. No party filed for rehearing, and Xcel Energy submitted the required compliance filings. Once the compliance filings are accepted, the rate case will be complete. The rate change is expected to increase 2008 NSP System transmission revenues by approximately $2.7 million.

MISO Long-Term Transmission Pricing In October 2005, MISO filed a proposed change to its Transmission and Energy Markets Tariff of MISO (TEMT) to regionalize future cost recovery of certain high voltage transmission projects to be constructed for reliability improvements. The tariff, called the Regional Expansion Criteria Benefits phase I (RECB I) and a subsequent proposal based on regional economic benefits (RECB II), would recover varying percentages of eligible reliability transmission costs from all transmission service customers in the MISO 15 state region. In November 2006, the FERC issued an order accepting the RECB I tariff, including the 20 percent limitation, which is the cap on the portion of transmission expansion costs that would be regionalized and recovered from all loads in the MISO region, with 80 percent allocated to the pricing zone where the transmission facilities are constructed. In December 2006, the Public Service Commission of Wisconsin (PSCW) and other parties filed an appeal of the RECB I order to the U.S. federal Court of Appeals for the District of Columbia. The appeal is pending.

In March 2007, the FERC issued an order approving most aspects of the RECB II proposal. Transmission service rates in the MISO region presently use a rate design in which the transmission cost depends on the location of the load being served (referred to as license plate rates). Costs of existing transmission facilities are thus not regionalized. MISO and its transmission owners filed a successor rate methodology in August 2007, to be effective February 2008. Other entities sought to regionalize some of these costs. The impact of the regionalization of future facilities would depend on the specific facilities placed in service. In January 2008, the FERC issued an order accepting the MISO filing to continue use of license plate rates for existing facilities and RECB (limited regionalization) pricing for certain new facilities. The requests for rehearing are pending FERC action.

Revenue Sufficiency Guarantee Charges In April 2006, the FERC issued an order determining that MISO had incorrectly applied its TEMT regarding the application of the revenue sufficiency guarantee (RSG) charge to certain transactions. The FERC ordered MISO to resettle all affected transactions retroactive to April 2005. The RSG charges are collected from MISO customers and paid to generators. In October 2006, the FERC issued an order granting rehearing in part and reversed the prior ruling requiring MISO to issue retroactive refunds and ordered MISO to submit a compliance filing to implement prospective changes.

In March 2007, the FERC issued orders separately denying rehearing of the October 2006 FERC order. Several parties have filed separate appeals to the D.C. Circuit Court seeking judicial review of the FERC s determinations of the allocation of

RSG costs among MISO market participants. In 2007, several other utilities filed a complaint against MISO at the FERC, challenging the MISO s current FERC-approved methodology for the recovery of RSG costs. In November 2007, the FERC issued an order that instituted a proceeding in these dockets to review evidence and to establish an RSG cost allocation methodology for market participants under the Midwest ISO Tariff. The refund-effective date established was Aug. 10, 2007. In March 2008, MISO filed revisions to its TEMT, reflecting an alternative mechanism for allocating RSG charges and costs. MISO stated that it included a real-time RSG cost allocation methodology, developed based on principles discussed in stakeholder discussions (but not yet conformed to incorporate new Ancillary Services Market (ASM) design elements). MISO stated that this new allocation methodology cannot be implemented prior to the start of the ASM and would be applied only prospectively. These proceedings are pending at the FERC.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings PSCW

Base Rate

Electric and Gas Rate Case In January 2008, the PSCW issued the final written 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 a natural gas rate increase of $5.3 million, or 3.3 percent. The rate increase was based on a 10.75 percent ROE and a 52.5 percent common equity ratio. New rates went into effect Jan. 9, 2008.

Other

2008 Electric Fuel Cost Recovery On April 7, 2008, NSP-Wisconsin filed an application with the PSCW requesting authorization to implement an electric fuel surcharge to increase electric rates by $19.7 million, or 3.8 percent, on an annual basis, with an effective date of May 1, 2008. NSP-Wisconsin expects the PSCW to issue an order approving interim rates, subject to refund. If the application is approved as filed, NSP-Wisconsin expects that the surcharge will generate approximately $13.2 million in additional revenue in 2008. The surcharge was requested because fuel and purchased power costs, including replacement power costs associated with unplanned plant outages, are expected to be significantly higher than approved by the PSCW in NSP-Wisconsin s 2008 rate case.

Financing Certificates of Authority In January 2008, NSP-Wisconsin filed an application with the PSCW for a certificate of authority to increase its previously approved short-term borrowing authority from $75 million to $150 million until such time NSP-Wisconsin completes its scheduled financing plan, at which time the authorization can decrease to $100 million; increase its short-term borrowing authority from NSP-Minnesota from $75 million to $150 million; and issue and sell up to $250 million aggregate principal amount of first mortgage bonds, debentures, notes, or other long-term indebtedness. NSP-Wisconsin intends to use the proceeds of the long-term debt issuance to refinance or replace existing long-term debt totaling up to $145 million and use the remainder to repay outstanding short-term debt. NSP-Wisconsin expects to issue long-term debt in 2008, but the exact timing and amount of the issuance will depend upon market conditions. The PSCW issued a certificate of authority and orders approving NSP-Wisconsin s short- and long-term financing applications in April 2008.

Bay Front Emission Controls Certificate of Authority In February 2008, NSP-Wisconsin filed an application with the PSCW seeking a certificate of authority to install equipment relating to combustion improvement and nitrogen oxide (NOx) emission controls in boilers 1 and 2 at the Bay Front power plant in Ashland County, Wisconsin. In March 2008, the PSCW issued a certificate of authority and order approving the project. Construction is expected to begin in May and is expected to be completed in the fall of 2008.

PSCo

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

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Adjustment Rider In September 2007, PSCo filed with the CPUC a request to implement a transmission cost adjustment rider (TCA), which would recover approximately $18.2 million in 2008. This filing is pursuant to recently enacted legislation, which entitled public utilities to recover, through a separate rate adjustment clause, the costs that it prudently incurs in planning, developing and completing the construction or expansion of transmission. This legislation further encourages utilities to invest in transmission facilities by allowing the recovery of the total balance of construction work in progress related to those transmission investments.

In November 2007, PSCo updated its estimate of costs to be recovered through the TCA commencing Jan. 1, 2008, reducing its requested recovery during 2008 to $8.7 million.

In December 2007, the CPUC issued its initial decision approving PSCo s application to implement the TCA. The CPUC limited the scope of the costs that could be recovered through the rider during 2008 to only those costs associated with transmission investment made after the new legislation authorizing the rider became effective on March 26, 2007. The CPUC also will require PSCo to base its revenue requirement calculation on a thirteen-month average net transmission plant balance. As a result of the CPUC s decision, PSCo implemented a rider on Jan. 1, 2008, to recover approximately $4.5 million in 2008.

Enhanced Demand Side Management (DSM) Program In October 2007, PSCo filed an application with the CPUC for approval to implement an expanded DSM program and to revise its DSM cost adjustment mechanism (DSMCA) to include current cost recovery and incentives designed to reward PSCo for successfully implementing cost-effective DSM programs and measures. With this application, PSCo proposes to expand and extend its commitment to acquire a cumulative level of 694 MW of peak demand reduction and 2,351 GWh of energy savings, including achievements associated with its existing DSM programs for 2009. Under the proposed revision to the DSMCA, PSCo would recover 100 percent of its forecasted expenses associated with the DSM program during the year in which the rider is in effect as well as an incentive based upon the net economic benefits achieved during the prior year up to 20 percent of the net present value of the benefits achieved. PSCo filed rebuttal testimony in April 2008 agreeing with a CPUC staff recommendation to 100 percent lost margins plus an incentive of up to 10 percent of the net economic benefit.

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 an active participant in the hearings. In September 2001, the presiding administrative law judge (ALJ) concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence regarding the use of certain strategies and how they may have impacted the markets in the Pacific Northwest markets. For the referenced period, parties have claimed that the total amount of transactions with PSCo subject to refund are $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC s orders in this proceeding with the U. S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Ninth Circuit remanded the proceeding back to the FERC. The court of appeals preliminarily determined that it had jurisdiction to review the FERC s decision not to order refunds and remanded the case back to the FERC, directing that the FERC consider evidence that had been presented regarding intentional market manipulation in the California markets and its potential ties to transactions in the Pacific Northwest. The court of appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The FERC has yet to act on this order on remand.

PSCo Wholesale Rate Case In February 2008, PSCo requested a $12.5 million increase, or a 5.88 percent in wholesale rates, based on 11.5 percent requested ROE. The $12.5 million total increase was composed of $8.8 million of traditional base rate recovery and $3.7 million of construction work in progress (CWIP) recovery for the Comanche 3 and Fort St. Vrain projects. The increase is applicable to all wholesale firm service customers with the exception of Intermountain Rural Electric Cooperative, which is under a rate moratorium until January 2009.

In March 2008, PSCo reached an agreement with Holy Cross, Yampa Valley and Grand Valley (REA s), which will resolve all issues based on a black box settlement with an implied ROE of 10.4 percent. Parties filed the settlement with the FERC on April 17, 2008, with rates effective May 1, 2008. PSCo has reached an agreement with the cities of Burlington and Center, as well as Aquila under the same substantive terms and conditions as the REA settlement, which was filed with the FERC on April 25, 2008. The settlements provide for:

- A traditional annual rate base rate increase of $6.6 million with allowance for funds used during construction continuing for Comanche and Fort St. Vrain.
- Implementation of new rates several months earlier than is typical in a disputed filing.
- The ability to implement rates in PSCo s next general rate case that will involve Comanche 3 costs upon a nominal suspension.

SPS

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

Base Rate

Application to Increase Voltage-Level Line Loss Factors In January 2008, the PUCT approved SPS application to update its current Texas retail fuel factors to reflect revised loss factors. Under the Texas retail base rate case, SPS was permitted to implement the revised line loss factors effective to May 2007. SPS recognized $6.2 million in the fourth quarter of 2007 for the impact of the revised line loss factors from May 1, 2007 through Dec. 31, 2007.

Electric and Resource Adjustment Clauses

TCR Factor Rulemaking The PUCT adopted, in November 2007, new rules relating to TCR factor outside of a base rate case. The rule establishes the mechanism by which SPS can request annual recovery of its reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges that are not included in existing rates. This new rule allows SPS more timely recovery of transmission cost increases in-between base rate cases.

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

Base Rate

New Mexico Electric Rate Case On July 30, 2007, SPS filed a request for a retail electric general rate increase of $17.3 million annually, or 6.6 percent, with the New Mexico Public Regulation Commission (NMPRC). The rate filing is based on 2006 historic test year adjusted for known and measurable changes and includes a requested ROE of 11.0 percent, an electric rate base of approximately $307.3 million and an equity ratio of 51.2 percent.

Following is a summary of intervenor and NMPRC staff testimony, which was filed on March 6, 2008:

- NMPRC staff recommended an increase of approximately $8 million based on a 9.1 percent ROE and other adjustments.
- The attorney general recommended a $2 million rate decrease based on a 9.2 percent ROE and other adjustments.
- Occidental Permian, a large retail customer, recommended a 9.9 percent ROE.

Hearings were held in April 2008. At the close of the hearings, the parties agreed to move consideration of the Lea Power Partners (Lea Power) rider costs to a future rate proceeding to be initiated by Xcel Energy this summer, which will be accompanied with a request for interim relief, so that issues associated with lease accounting and potential contract restructuring, discussed in the Management s Discussion and Analysis section of this report, may be adequately addressed. The remaining procedural schedule is as follows:

• Recommend decision	June 30, 2008
• Final order	Aug. 29, 2008

Electric and Resource Adjustment Clauses

New Mexico Fuel Factor Continuation Filing In August 2005, SPS filed with the NMPRC requesting continuation of the use of SPS fuel and purchased power cost adjustment clause (FPPCAC) and current monthly factor cost recovery methodology. This filing was required by NMPRC rule.

Testimony was filed in the case by staff and intervenors objecting to SPS assignment of system average fuel costs to certain wholesale sales and the inclusion of certain purchased power capacity and energy payments in the FPPCAC. The testimony also proposed limits on SPS future use of the FPPCAC. Related to these issues, some intervenors requested disallowances for past periods, which in the aggregate total approximately $45 million. This claim was for the period from Oct. 1, 2001 through May 31, 2005 and does not include the value of incremental cost assigned for wholesale transactions from that date forward. Other issues in the case include the treatment of renewable energy certificates and sulfur dioxide (SO_2) allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause.

In December 2007, SPS, the NMPRC, Occidental Permian Ltd. and the New Mexico Industrial Energy Consumers (NMIEC) filed an uncontested settlement of this matter with the NMPRC.

- The settlement resolves all issues in the fuel continuation proceeding for total consideration of $15 million, which includes customer refunds of $11.7 million.
- At Dec. 31, 2007, a reserve had been previously established for this potential exposure, with no further expense accrual required, assuming this settlement is approved.
- The settlement would also provide for significantly greater certainty surrounding system average fuel cost assignment on a going forward basis and reduce percentages of system average cost wholesale sales between now and 2019 on a stepped down basis.
- Under the terms of the settlement, SPS anticipates additional fuel cost disallowances in 2008 and a portion of 2009 of approximately $2 million per year. It does not anticipate any future disallowances beyond this period.
- Finally, the settlement provides for SPS to continue its use of the FPPCAC subject to additional reporting provisions.

A hearing on the merits of the settlement was held in April 2008. The parties are to provide the hearing examiner with a proposed certification of the settlement on May 2, 2008, which will recommend approval of the settlement. Any objections to the proposed certification are due on May 9, 2008.

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 to them 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 complainant asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to 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 administrative law judge (ALJ) issued an initial decision in the proceeding. The ALJ found that SPS should recalculate its wholesale 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 from such costs the incremental fuel costs attributed to SPS sales of system firm capacity and associated 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 and the use of a 3-month coincident peak (3CP) demand allocator.

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 with a minor modification to the formula rate proposed by the FERC and accepted by the parties. The Settlement provides for:

- A $1.25 million payment by SPS to Golden Spread related to resolve a dispute concerning the quantities Golden Spread was entitled to take under its existing partial requirements agreement for the years 2006 and 2007. The Settlement caps those quantities for the period 2008 through 2011. SPS is not required to make any fuel refunds to Golden Spread that were the subject of the Complaint under the terms of the Settlement.

- An extended partial requirements contract at system average cost, with a capacity amount that ramps down over the period 2012 through 2019 from 500 MW to 200 MW. The extended agreement requires that the cost assignment treatment receive Texas and New Mexico state approvals and provides for alternative pricing terms and quantities to hold SPS harmless from cost disallowances in the event that adverse regulatory treatment occurs or state approvals are not obtained. 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.

- Resolution of base rates in the Complaint without any adjustment to the existing rates for the period January 2005 through June 30, 2006. The Settlement also resolves all base rate issues in SPS subsequent proceeding related to the period July 1, 2006 through June 30, 2008, other than the method to be used to allocate demand related costs and provided for two sets of agreed on rates that are dependent on the ultimate resolution of that issue. If SPS prevails in its support of the 12 month coincident peak (12 CP) demand allocation method, there would be no impact to earnings for this period. If Golden Spread prevails, SPS would be required to refund Golden Spread and PNM approximately $4 million for the period through the end of 2007.

- For July 1, 2008 and beyond, Golden Spread will be under a formula rate for power supply service. The rate will be based on actual data the most recent historic year adjusted for known and measurable changes and trued up to the actual performance in the subsequent calendar year. Initially, the formula will be based on a 10.25 percent ROE and either party will have a right to seek changes to the ROE beginning with the 2009 formula rate filing. SPS and Golden Spread will share margins from its sales to West Texas Municipal Power Agency (WTMPA) and El Paso Electric (EPE) in that year but will assign system average fuel and energy costs to those agreements for purposes of calculating Golden Spread s monthly fuel cost.

Order on Wholesale Rate Complaints On April 21, 2008, the FERC issued its Order on the Complaint (the Order) 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 return on equity 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 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 in July 1, 2006, are the subject of settlements that have either been approved or are pending before FERC. These settlements are described in Wholesale 2005 Power Base Rate Application below.

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 within 30 days of the date of the Order 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 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 Qualifying Facility (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 the all of the individual wind contracts as well as the QF purchases are typically economic when compared to market energy prices.

As of March 31, 2008, SPS has accrued an amount, sufficient to cover the refund obligation.

Wholesale 2005 Power Base Rate Application In December 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. In January 2006, the FERC conditionally accepted the proposed rates for filing and the $2.5 million power rate increase became effective on July 1, 2006, subject to refund. The FERC also set the rate increase request for hearing and settlement judge procedures. In September 2006, offers of settlement with respect to the five full-requirements customers and with respect to PNM were filed for approval. In September 2007, the FERC accepted the settlement with the full-requirements customers. The PNM settlement is still pending before the FERC.

As noted, the Wholesale 2005 Power Base Rate Application relating to Golden Spread was settled in conjunction with the Complaint Settlement discussed above. Therefore, SPS has settled with all parties in the Wholesale 2005 Power Base Rate

Application except for resolution with Golden Spread of the demand cost allocation methodology. A hearing on the demand allocation methodology has been set for July 29, 2008. An Initial Decision expected by the end of September 2008.

SPS Formula Transmission 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 Southwest Power Pool Inc. (SPP) made a companion filing in January 2008, to implement the same pricing in the SPS zone of the SPP regional OATT. The changed rates will affect all wholesale transmission service customers using the SPS transmission network under either the SPP Regional OATT or the Xcel Energy OATT.

A formula rate will help facilitate the financing and construction of the new transmission facilities while providing an adequate rate of return on invested capital. The proposed 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 rate of return on common equity is 12.7 percent, including a 50 basis point adder for SPS participation in the SPP Regional Transmission Organization, consistent with FERC precedent. The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC issued an order accepting 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 regional transmission organization. In March 2008, the FERC accepted the companion SPP rate change filing subject to the outcome of the SPS rate filing. The SPS and SPP rate filings are now in settlement procedures. The ultimate outcome of the rate filings is not known at this time.

SPS 2008 Wholesale Rate Case On March 31, 2008, SPS filed a wholesale power base rate case in the full-requirements customers base rates. SPS is seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. On April 21, 2008, a motion for dismissal and protest was filed by the four eastern New Mexico cooperatives. A FERC decision is expected later in 2008.

7. Commitments and Contingent Liabilities

Except to the extent noted below, the circumstances set forth in Notes 14, 15 and 16 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, 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 other 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 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 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 and some other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including the following categories of sites:

- 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 potentially responsible party (PRP) that sent hazardous materials and wastes.

Xcel Energy records a liability when enough information is obtained to develop an estimate of the cost of environmental remediation and revises the estimate as information is received. The estimated remediation cost may vary materially from the initial estimate.

To estimate the remediation cost for these sites, assumptions are made when facts are not fully known. For instance, assumptions may be made about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution-control technologies, the period over which remediation will be performed and paid for, changes in environmental remediation and pollution-control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

Estimates are revised as facts become known. At March 31, 2008, the liability for the cost of remediating these sites was estimated to be $46.7 million, of which $2.4 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

- Insurance coverage;
- Other parties that have contributed to the contamination; and
- Customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. Estimates have been recorded for Xcel Energy s future costs for these sites.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site NSP-Wisconsin was 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 Chequemegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A determination of the scope and cost of the remediation of the Ashland site is not currently expected until early 2009. NSP-Wisconsin continues to work with the Wisconsin Department of Natural Resources (WDNR) to access state and federal funds to apply to the ultimate remediation cost of the entire site.

In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) Program 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 2007, NSP-Wisconsin spent $1.5 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. 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. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup. In September 2007, the EPA approved the series of reports included in the remedial investigation (RI) report. The draft feasibility study, which develops and assesses the alternatives for cleaning up the site, was prepared by NSP-Wisconsin and was submitted to the EPA in October 2007. The range of remediation costs set forth in the draft feasibility study is between $35.8 million and $125.5 million. In February 2008, the EPA provided written comments on the October 2007 draft feasibility study submitted by NSP-Wisconsin. NSP-Wisconsin has until May 15, 2008 to submit a revised draft feasibility study based upon the EPA s comments.

In October 2004, the WDNR 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 lawsuit has been stayed. NSP-Wisconsin has recorded an estimate of its potential liability. All costs paid to the WDNR are expected to be recoverable in rates.

In addition to potential liability for remediation and WDNR oversight costs, 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 is not able to estimate its potential exposure for NRD at the site, but has recorded an estimate of its potential liability based upon the minimum of its estimated range of potential exposure.

Until the EPA and the 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. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, that portion of the recorded liability related to remediation is based upon the minimum of the estimated range of remediation costs, contained in the draft feasibility study. NSP-Wisconsin has recorded a liability of $43.6 million for its potential liability related to the Ashland site, including potential liability for remediation of the Ashland site, WDNR oversight costs, NRD claims, outside legal and consultant costs 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.

Fort Collins Manufactured Gas Plant Site Prior to 1926, the Poudre Valley Gas Co. operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the assets of the Poudre Valley Gas Co., PSCo shut down the MGP site and has subsequently sold most of the property. In 2002, an oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. In November 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co. (Schrader) under which PSCo performed remediation and monitoring work. PSCo has substantially completed work at the site, with the exception of ongoing maintenance and monitoring.

In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional clean-up costs at the Fort Collins MGP site spent through September 2006, plus unrecovered amounts previously authorized from the last rate case, which amounted to $10.8 million to be amortized over four years. In June 2007, PSCo entered into a settlement agreement that included recovery of the full $10.8 million, but with a five-year amortization period. The CPUC approved the agreement on June 18, 2007. The total amount to be recovered from customers is $13.1 million. Estimated future project costs, based upon an assumed 30-year system operating life, including EPA oversight costs, are approximately $3.9 million.

In April 2005, PSCo brought a contribution action against Schrader and related parties alleging Schrader released hazardous substances into the environment and these releases caused MGP byproducts to migrate to the Cache la Poudre River, thereby substantially increasing the scope and cost of remediation. PSCo requested damages, including a portion of the costs PSCo incurred to investigate and remove contaminated sediments from the Cache la Poudre River. In December 2005, the court denied Schrader s request to dismiss the PSCo suit. Schrader thereafter filed a response to the PSCo complaint and a counterclaim against PSCo for its response costs under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and under the Resource Conservation and Recovery Act (RCRA). Schrader alleged as part of its counterclaim an imminent and substantial endangerment of its property as defined by RCRA. PSCo filed a motion for partial summary judgment to dismiss Schrader s RCRA claim. In October 2007, the court granted PSCo s motion for partial summary judgment and dismissed Schrader s RCRA claim. Schrader also filed a motion for summary judgment seeking to dismiss PSCo s CERCLA claim. In April 2008, the court denied Schrader s motion for summary judgment and scheduled the case for a September 2008 trial. Any costs recovered from Schrader are expected to credit ratepayers.

Third Party and Other Environmental Site Remediation

Asbestos Removal Some of our 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.

See additional discussion of asset retirement obligations in Note 15 of the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007. 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

Clean Air Interstate Rule In March 2005, the EPA issued the Clean Air Interstate Rule (CAIR) to further regulate SO_2 and nitrogen oxide (NOx) emissions. The objective of CAIR is to cap emissions of SO_2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy s service territory. Xcel Energy generating facilities in other states are not affected. CAIR addresses the transportation of fine particulates, ozone and emission precursors to nonattainment downwind states. CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO_2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO_2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

In July 2005, SPS, the City of Amarillo, Texas and Occidental Permian LTD filed a lawsuit against the EPA and a request for reconsideration with the agency to exclude West Texas from the CAIR. El Paso Electric Co. joined in the request for reconsideration. Xcel Energy and SPS advocated that West Texas should be excluded from CAIR because it does not contribute significantly to nonattainment with the fine particulate matter standards in any downwind jurisdiction.

In March 2006, the EPA denied the petition for reconsideration and in June 2006, Xcel Energy and the other parties filed a petition for review of the denial of the petition for reconsideration, as well as a petition for review of the Federal Implementation Plan, with the D.C. Circuit Court of Appeals. The Court has taken this matter under advisement and a decision is expected in due course.

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. Based on the preliminary analysis of various scenarios of capital investment and allowance purchase, Xcel Energy currently believes that after the installation of low NOx burners on Harrington 3 in 2006, the remaining capital investments for NOx controls in the SPS region are estimated at $12 million. Purchases of NOx allowances are estimated at $2.1 million in 2009 with no NOx allowance needs in 2010. Annual purchases of SO_2 allowances are estimated in the range of $5 million to $25 million each year, beginning in 2012, for phase I, based on allowance costs and fuel quality as of March 2007. These cost estimates represent one potential scenario on complying with CAIR, if West Texas is not excluded.

In addition, Minnesota and Wisconsin will be included in CAIR, and Xcel Energy has generating facilities in these states that will be impacted. Preliminary estimates of capital expenditures associated with compliance with CAIR in Minnesota and Wisconsin range from $30 million to $40 million. Xcel Energy is not challenging CAIR in these states. Purchases of NOx allowances for NSP-Minnesota in 2009 are estimated at $9.2 million in 2009 with no NOx allowance needs in 2010. For NSP-Wisconsin, purchases of CAIR NOx allowances are estimated at $2.4 million in 2009 and $2.1 million in 2010.

While Xcel Energy expects to comply with the new rules through a combination of additional capital investments in emission controls at various facilities and purchases of emission allowances, it is continuing to review the alternatives. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates.

Clean Air Mercury Rule In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR), which regulated mercury emissions from power plants. On Feb. 8, 2008, the D.C. Circuit Court of Appeals 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 below.

In Colorado, the Air Quality Control Commission 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 all other Colorado units by 2014. Xcel Energy is in the process of installing mercury monitors on seven Colorado units at an estimated aggregate cost of approximately $2.6 million. Xcel Energy is evaluating the emission controls required to meet the state rule and is currently unable to provide a capital cost estimate.

In the SPS region, the Texas Commission on Environmental Quality (TCEQ) adopted by reference the EPA model program. Given the many uncertainties created by the decision of the D.C. Circuit Court of Appeals to vacate CAMR, it is not possible at this time to provide an accurate summary of applicable federal mercury requirements or cost estimates.

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 Xcel Energy, the Act covers units at the A. S. King and Sherco generating facilities. Under the Act, Xcel Energy is operating and maintaining continuous mercury emission monitoring systems. The information obtained will be used to establish a baseline from which to measure mercury emission reductions. Mercury emission reduction plans were required to be filed by utilities by Dec. 31, 2007 (dry scrubbed units) and Dec. 31, 2009 (wet scrubbed units) that propose to implement technologies most likely to reduce emissions by 90 percent. Implementation would occur by Dec. 31, 2009 for one of the dry scrubbed units, Dec. 31, 2010 for the remaining dry scrubbed unit and Dec. 31, 2014 for wet scrubbed units. The cost of controls will be determined as part of the engineering analysis portion of the mercury reduction plans and is currently estimated to range from $26.5 to $854.5 million for the mercury control and continuous monitoring equipment for Sherco units 1, 2 and 3 and for A.S. King, with increased operating and maintenance expenses estimated to range from approximately $24.7 to $77.2 million. The lower values include costs to achieve a 50 percent mercury reduction for Sherco units 1 and 2 and a 90 percent mercury reduction for Sherco unit 3 and A. S. King. The higher values include costs to achieve a 90 percent mercury reduction for all Sherco units, as well as for A. S. King. Utilities subject to the Act may also submit plans to address non-mercury pollutants subject to federal and state statutes and regulations, which became effective after Dec. 31, 2004. Cost recovery provisions of the Act also apply to these other environmental initiatives. In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs that are expected to be 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. To date, NSP-Minnesota has spent approximately $1.3 million on mercury monitoring implementation.

Voluntary Capacity Upgrade and Emissions Reduction Filing In December 2007, NSP-Minnesota filed a plan with the MPCA and MPUC for reducing mercury emissions by up to 90 percent at the Sherco unit 3 and King plants. Estimated project costs amount to approximately $9.1 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 and encompasses the higher value mercury control costs discussed above in the Minnesota Mercury Legislation section. 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.

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. Some of these facilities are located in regions where CAIR is effective. CAIR has precedence over BART. Therefore, BART requirements will be deemed to be met through compliance with CAIR requirements.

The EPA required states to develop implementation plans to comply with BART by December 2007. States are required to identify the facilities that will have to reduce SO_2, NO_x, and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado Air Quality Control Commission (AQCC) promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of the BART alternatives will cost approximately $211 million in capital costs, which includes approximately $62 million in environmental upgrades for the existing Comanche Station project, 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 2011 and 2014. On June 4, 2007, the Colorado Air Pollution Control Division (CAPCD) approved PSCo s BART analysis and obtained public comment on its BART determination and PSCo s BART permits. The AQCC approved the CAPCD s BART determination for PSCo during a public hearing in December 2007. CAPCD s BART determinations and corresponding provisions of the regional haze state implementation plan will be submitted to the EPA for approval in 2008. In addition, in early 2008, the CAPCD initiated a stakeholder process to establish reasonable progress goals for Colorado s Class I areas. To meet these goals, more controls may be required from certain sources, which may or may not include those sources previously controlled under BART.

NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 in October 2006. The Minnesota Pollution Control Agency (MPCA) reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. At this time, the MPCA is not requiring any BART specific controls that go beyond controls required for CAIR compliance.

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 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 challenging the phase II rulemaking. In January 2007, the court issued its decision and remanded virtually every aspect of 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 court-ordered remand. As a result, the rule s compliance requirements and associated deadlines are currently unknown. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved.

Maddox Station Groundwater The New Mexico Environment Department (NMED) is requiring wastewater activity at Maddox Station to be permitted. SPS is developing the permit application and engineering wastewater management facilities. The estimated cost of the project is $1.8 million with an anticipated completion date in the third quarter of 2009.

New York Office of the Attorney General Subpoena In September 2007, the Office of the New York Attorney General (NYAG) issued a subpoena pursuant to the Martin Act, a New York statute, to Xcel Energy. The subpoena seeks information and documents related to Xcel Energy s analysis of risks posed by climate change and possible climate legislation and its disclosures of such risks to investors. In a letter accompanying the subpoena, the NYAG asserts that the increase in carbon dioxide (CO_2) emissions upon completion of Comanche 3 (a coal-fired unit), in combination with Xcel Energy s other coal-fired plants, will subject Xcel to increased financial, regulatory and litigation risks which need to be disclosed to shareholders. Xcel Energy believes it has fully disclosed these risks, to the extent they can be ascertained, and such disclosures belie the concerns expressed by the NYAG.

PSCo Notice of Violation In July 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche and Pawnee plants 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. It 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.

Cherokee Station Alleged Clean Air Act Violations In January 2008, Xcel Energy received a notice letter from Rocky Mountain Clean Air Action stating that the group intends to sue Xcel Energy for alleged Clean Air Act violations at Cherokee Station. The group claims that Cherokee Station s opacity emissions have exceeded allowable limits over the past five years and that its opacity monitors exceeded downtime limits. Xcel Energy disputes these claims and believes they are without merit. The Clean Air Act requires notice be given 60 days prior to filing a lawsuit. If the group does in fact file its threatened lawsuit, Xcel Energy will vigorously defend itself against these claims.

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 was a subsidiary of Xcel Energy Markets Holdings Inc., which 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. Twelve 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.* The other eleven 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 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. An exception is *the Missouri Public Service Commission* case, which was remanded to Missouri state court in November 2007.

In April 2005, Judge Pro granted defendants motion to dismiss in *Texas Ohio Energy* based upon the filed rate doctrine. Based upon this same legal doctrine, Judge Pro subsequently granted defendants motion to dismiss in *Fairhaven Power Company, Ableman Art Glass and Utility Savings and Refund Services*. Plaintiffs subsequently appealed these dismissals to the Ninth Circuit Court of Appeals. In September 2007, the Ninth Circuit Court of Appeals reversed the dismissal and remanded the lawsuits to Judge Pro for consideration of whether any of plaintiffs claims are based upon retail rates not directly barred by the filed rate doctrine. e prime and some other defendants were dismissed from the *Breckenridge* 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.

All of the gas trading lawsuits are in the early procedural stages of litigation. No trial dates have been set for any of these lawsuits; however, defendants motions to dismiss are pending in the *Missouri Public Service Commission* matter, and defendants summary judgment motions are pending in the *Learjet and J.P. Morgan* matters.

Cabin Creek Hydro Generating Station Accident

On Oct. 2, 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. At approximately 2:00 p.m., 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), U.S. Chemical Safety Board and the Colorado Bureau of Investigations. In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. On April 11, 2008, Xcel Energy notified OSHA that it intends to contest all of the proposed citations.

Environmental Litigation

Comanche 3 Permit Litigation In August 2005, Citizens for Clean Air and Water in Pueblo and Southern Colorado and Clean Energy Action filed a complaint in Colorado state court against the CAPCD alleging that the division improperly granted permits to PSCo under Colorado s Prevention of Significant Deterioration program for the construction and operation of Comanche 3. PSCo intervened in the case. In June 2006, the court ruled in PSCo s favor and held that the Comanche 3 permits had been properly granted and plaintiffs claims to the contrary were without merit. Plaintiffs appealed the decision. In February 2008, the Colorado Court of Appeals affirmed the state court s decision. Plaintiffs filed a petition with the Colorado Supreme Court seeking discretionary review of the appellate court decision.

Carbon Dioxide Emissions Lawsuit In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO_2 emissions. In October 2004, Xcel Energy and the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the court granted the motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the Second Circuit Court of Appeals. In June 2007 the Second Circuit Court of Appeals issued an order requesting the parties to file a letter brief regarding the impact of the United States Supreme Court s decision in Massachusetts v. EPA, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in Massachusetts v. EPA, the United States Supreme Court held that CO_2 emissions are a pollutant subject to regulation by the EPA under the Clean Air Act. In response to the request of the Second Circuit Court of Appeals, in June 2007, the defendant utilities filed a letter brief stating the position that the United States Supreme Court s decision supports the arguments raised by the utilities on appeal. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

Comer vs. Xcel Energy Inc. et al. **In April 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants CO_2 emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal**

theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. In September 2007, plaintiffs filed a notice of appeal to the Fifth Circuit Court of Appeals. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

Native Village of Kivalina vs. Xcel Energy Inc. et al. **In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit against Xcel Energy and 23 other 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 carbon dioxide and other greenhouse gases 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. A response to the complaint is due on or before June 30, 2008.**

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy In June 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota s distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. After its motion to dismiss plaintiffs claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007, the court granted NSP- Minnesota s motion for certification, and the parties have filed briefs on appeal.

Saemrow Dairy Partnership vs. Xcel Energy In December 2006, 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 and in the construction and maintenance of distribution systems. They also alleged 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 approximately $9 million. NSP-Minnesota denies all allegations. A confidential settlement of this matter was reached at mediation in March 2008 and will not have a material financial impact on NSP-Minnesota or Xcel Energy.

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 Denver state court. 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. In January 2008, Qwest filed a notice of appeal.

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. On Jan. 22, 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 have petitioned the Minnesota Supreme Court for discretionary review, and on April 15, 2008, the court granted the petition. The matter will be briefed by both parties, followed by an oral argument at a future date.

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 circuit 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.

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 eleven insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Court of Appeals for Minnesota challenging the dismissal of these carriers. In November 2007, Ranger Insurance Company (Ranger) and TIG Insurance Company (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.

In April 2008, the Court of Appeals issued an order staying briefing until further order of the court. The order was issued in response to NSP-Wisconsin s request that oral argument be deferred pending a decision by the Wisconsin Supreme Court in Plastics Engineering Co. vs. Liberty Mutual Insurance Co. In *Plastics Engineering Co.,* the Wisconsin Supreme Court will consider the method of allocation to be adopted in Wisconsin.

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

Nuclear Waste Disposal Litigation In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy s (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. 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 appellate court to stay briefing until the appeals in several other nuclear waste cases have been decided. Results of the judgment will not be recorded in earnings until the appeal and regulatory treatment and amounts to be shared with ratepayers has 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 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 claims damages for the period Jan. 1, 2005 through June 30, 2007, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and NativeVillage of Kivalina, Alas

costs of complying with state regulation relating to the storage of spent nuclear fuel. The amount of such damages is expected to exceed $40 million. In January 2008, the court granted the DOE s motion to stay, subject to reevaluation after a decision has been filed in any one of the five pending appeals of nuclear waste storage cases.

Mallon vs. Xcel Energy Inc. In July 2007, Theodore Mallon and TransFinancial Corporation filed a declaratory judgment action against Xcel Energy in U. S. District Court in Colorado (Mallon Federal Action). In this lawsuit, plaintiffs seek a determination that Xcel Energy is not entitled to assert claims against plaintiffs related to the 1984 and 1985 sale of COLI to PSCo, a predecessor of Xcel Energy. In August 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in Colorado state court against Mallon and TransFinancial Corporation (Mallon State Action). In the Mallon State Action, Xcel Energy, PSCo and PSRI seek damages against Mallon and TransFinancial for, among other things, breach of contract and breach of fiduciary duties associated with the sale of the COLI policies. In August 2007, Xcel Energy also filed a motion to stay or, in the alternative, to dismiss the Mallon Federal Action. In September 2007, a motion to stay the Mallon State Court action was subsequently filed by Mallon and TransFinancial. In November 2007, the U.S. District Court in Colorado dismissed the

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and NativeVillage of Kivalina, Alas

complaint in the Mallon Federal Action and Mallon and TransFinancial subsequently withdrew their motion to stay the Mallon State Court Action.

Fru-Con Construction Corporation vs. Utility Engineering (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 District Court in Travis County, Texas. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the District Court s decision to the Court of Appeals for the Third Supreme Judicial District of the state of Texas. This appeal is currently pending.

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. An adverse ruling on the appeal of May 2003 PUCT order could result in a different determination of the legality of SPS service to the disputed customers.

8. Short-Term Borrowings and Other Financing Instruments

Short-Term Borrowings

Commercial Paper At March 31, 2008 and Dec. 31, 2007, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $377.9 million and $1,088.6 million, respectively. The weighted average interest rates at March 31, 2008 and Dec. 31, 2007 were 3.54 percent and 5.57 percent, respectively.

Guarantees

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and NativeVillage of Kivalina, Alas

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alask

Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On March 31, 2008 and Dec. 31, 2007, Xcel Energy had issued guarantees of up to $75.2 million with $17.5 million of known exposure under these guarantees. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of March 31, 2008 and Dec. 31, 2007, was approximately $31.7 million and $31.6 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

9. Long-Term Borrowings and Other Financing Instruments

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alas

Junior Subordinated Notes

On Jan. 16, 2008, Xcel Energy issued $400 million of 7.6 percent junior subordinated notes (Junior Notes) due 2068. Due to certain features, rating agencies consider the Junior Notes to be hybrid debt instruments with a combination of debt and equity characteristics. The Junior Notes are not redeemable by Xcel Energy prior to 2013 without payment of a make-whole premium. The proceeds from this offering were used to repay short-term debt.

Interest payments on the Junior Notes may be deferred on one or more occasions for up to 10 consecutive years. If the interest payments on the Junior Notes are deferred, Xcel Energy may not declare or pay any dividends or distributions, or redeem, purchase, acquire, or make a liquidation payment on, any shares of its capital stock. Also during the deferral period, Xcel Energy may not make any principal or interest payments on, or repay, purchase or redeem any of its debt securities that are equal in right of payment with, or subordinated to, the Junior Notes. Xcel Energy also may not make payments on any guarantees equal in right of payment with, or subordinated to, the Junior Notes.

In connection with the completion of this offering, Xcel Energy entered into a Replacement Capital Covenant (RCC) for the benefit of persons that buy, hold, or sell a specified series of Xcel Energy long-term indebtedness ranking senior to the Junior Notes. Initially, Xcel Energy s 6.50 percent Senior Notes due July 1, 2036, was specified as such series of long-term debt. Under the terms of the RCC, Xcel Energy agrees not to redeem or repurchase all or part of the Junior Notes prior to 2038 unless qualifying securities are issued to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Notes at the time of redemption or repurchase.

First Mortgage Bonds

On March 18, 2008, NSP-Minnesota issued $500 million of 5.25 percent first mortgage bonds, series due March 1, 2018. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement.

10. Derivative Instruments

Xcel Energy and its subsidiaries use derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The types of qualifying hedging transactions that Xcel Energy and its subsidiaries are currently engaged in are discussed below.

Cash Flow Hedges

Commodity Cash Flow Hedges Xcel Energy s utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At March 31, 2008, Xcel Energy had various commodity-related contracts designated as cash flow hedges extending through December 2009. The fair value of these cash flow hedges is recorded in other comprehensive income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. This could include the purchase or sale of energy or energy-related products, the use of natural gas to generate electric energy or gas purchased for resale.

At March 31, 2008, Xcel Energy had $0.4 million in accumulated other comprehensive income related to commodity cash flow hedge contracts that is expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Interest Rate Cash Flow Hedges Xcel Energy and its 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 March 31, 2008, Xcel Energy had $0.2 million in net losses in accumulated other comprehensive income related to interest rate swaps/locks that is expected to be recognized in earnings during the next 12 months.

The following table shows the major components of the derivative instruments valuation in the consolidated balance sheets at March 31 and Dec. 31:

(Thousands of Dollars)	March 31, 2008 Derivative Instruments Valuation - Assets	March 31, 2008 Derivative Instruments Valuation - Liabilities	Dec. 31, 2007 Derivative Instruments Valuation - Assets	Dec. 31, 2007 Derivative Instruments Valuation - Liabilities
Long term purchased power agreements	$ 413,754	$ 392,977	$ 426,774	$ 401,313
Electric and natural gas trading and hedging instruments	36,576	17,693	51,106	21,694
Interest rate hedging instruments	643	7,127	535	20,223
Total	$ 450,973	$ 417,797	$ 478,415	$ 443,230

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 the first quarter of 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.

The impact of qualifying 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 March 31, 2008	2007
Accumulated other comprehensive (loss) income related to cash flow hedges at Jan. 1	$ (1,416)	$ 2,196
After-tax net unrealized losses related to derivatives accounted for as hedges	(5,601)	(543)
After-tax net realized gains on derivative transactions reclassified into earnings	(25)	(257)
Accumulated other comprehensive (loss) income related to cash flow hedges at March 31	$ (7,042)	$ 1,396

Fair Value Hedges

Interest Rate Fair Value Hedges Xcel Energy enters into interest rate swap instruments that effectively hedge the fair value of fixed-rate debt. The fair market value of Xcel Energy s interest rate swaps at March 31, 2008, was an asset of approximately $0.6 million.

11. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

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

The following table presents, for each of these hierarchy levels, Xcel Energy s assets and liabilities that are measured at fair value on a recurring basis as of March 31, 2008:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Counterparty Netting (a)	Net Balance
Assets					
Nuclear decommissioning fund	$ 674,409	$ 486,687	$ 97,232	$	$ 1,258,328
Commodity derivatives	427	18,157	27,676	(9,684)	36,576
Interest rate derivatives		643			643
Total	$ 674,836	$ 505,487	$ 124,908	$ (9,684)	$ 1,295,547
Liabilities					
Commodity derivatives	$	$ 15,056	$ 12,321	$ (9,684)	$ 17,693
Interest rate derivatives		7,127			7,127
Total	$	$ 22,183	$ 12,321	$ (9,684)	$ 24,820

(a) FIN 39 permits the netting of receivables and payables when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

The following table presents the changes in Level 3 recurring fair value measurements for the three months ended March 31, 2008:

(Thousands of Dollars)	Commodity Derivatives, Net	Nuclear Decommissioning Fund
Balance, Jan. 1, 2008	$ 19,466	$ 108,656
Purchases, issuances, and settlements, net	(3,346)	(10,251)
Gains recognized in earnings	30	
Losses recognized as regulatory assets and liabilities	(795)	(1,173)
Balance, March 31, 2008	$ 15,355	$ 97,232

Gains on Level 3 commodity derivatives recognized in earnings for the three months ended March 31, 2008, include $2.5 million of net unrealized gains relating to commodity derivatives held at March 31, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric utility revenues. Realized and unrealized gains and losses on short-term wholesale activities reflect the impact of regulatory recovery and resulting deferral as regulatory assets and liabilities. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

12. Detail of Interest and Other Income, Net

Interest and other income, net of nonoperating expenses, for the three months ended March 31 consisted of the following:

(Thousands of Dollars)	Three months ended March 31, 2008	2007
Interest income	$ 7,510	$ 4,791

Equity income in unconsolidated affiliates	510	1,078
Other nonoperating income	1,567	620
Minority interest income	248	134
Insurance policy expenses	(899)	(5,775)
Other nonoperating expenses	(52)	(32)
Total interest and other income, net	$ 8,884	$ 816

13. Common Stock and Equivalents

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

For the three months ended March 31, 2008 and 2007, Xcel Energy had approximately 8.1 million and 10.8 million stock options that were antidilutive and excluded from the dilutive earnings per share calculation, respectively.

The dilutive impact of common stock equivalents affected earnings per share as follows for the three months ending March 31, 2008 and 2007:

	Three months ended March 31, 2008			Three months ended March 31, 2007		
(Amounts in thousands, except per share amounts)	**Income**	**Shares**	**Per-share Amount**	**Income**	**Shares**	**Per-share Amount**
Income from continuing operations	$ 153,994			$ 118,514		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Income from continuing operations	152,934	429,563	$ 0.35	117,454	408,003	$ 0.29
Effect of dilutive securities:						
Convertible debt	780	4,663		3,806	23,310	
401(k) equity awards		599			611	
Stock options		28			130	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 153,714	434,853	$ 0.35	$ 121,260	432,054	$ 0.28

14. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three months ended March 31,			
	2008 (1)	**2007 (1)**	**2008**	**2007**
(Thousands of Dollars)	**Pension Benefits**		**Postretirement Health Care Benefits**	
Service cost	$ 16,773	$ 16,485	$ 1,464	$ 1,701
Interest cost	40,583	39,598	12,546	13,603
Expected return on plan assets	(68,472)	(65,891)	(7,500)	(7,618)
Amortization of transition obligation			3,644	3,611
Amortization of prior service cost (credit)	5,166	6,487	(544)	(545)
Amortization of net loss	2,859	3,867	2,718	4,994
Net periodic benefit cost (credit)	(3,091)	546	12,328	15,746
Credits not recognized due to the effects of regulation	2,592	2,680		
Additional cost recognized due to the effects of regulation			973	973
Net benefit cost (credit) recognized for financial reporting	$ (499)	$ 3,226	$ 13,301	$ 16,719

(1) Includes qualified and non-qualified pension net periodic benefit cost.

15. Segment Information

Xcel Energy has the following reportable segments: regulated electric utility and regulated natural gas utility. Commodity trading operations performed by regulated operating companies are not a reportable segment. Commodity trading results are included in the regulated electric utility segment.

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Three months ended March 31, 2008					
Operating revenues from external customers	$ 1,973,314	$ 1,034,127	$ 20,947	$	$ 3,028,388
Intersegment revenues	246	2,626		(2,872)	
Total revenues	$ 1,973,560	$ 1,036,753	$ 20,947	$ (2,872)	$ 3,028,388
Income (loss) from continuing operations	$ 93,076	$ 67,566	$ 9,651	$ (16,299)	$ 153,994
Three months ended March 31, 2007					
Operating revenues from external customers	$ 1,815,803	$ 927,422	$ 20,437	$	$ 2,763,662
Intersegment revenues	329	4,388		(4,717)	
Total revenues	$ 1,816,132	$ 931,810	$ 20,437	$ (4,717)	$ 2,763,662
Income (loss) from continuing operations	$ 72,135	$ 56,921	$ 10,780	$ (21,322)	$ 118,514

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

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

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate, believe, estimate, expect, intend, may, objective, outlook, plan, project, possible, pote expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A of Xcel Energy s Form 10-K for the year ended Dec. 31, 2007, and Exhibit 99.01 to this report on Form 10-Q for the quarter ended March 31, 2008.

RESULTS OF OPERATIONS

Summary of Financial Results

The following table summarizes the earnings contributions. Continuing operations consist of the following:

- Regulated utility subsidiaries, operating in the electric and natural gas segments; and
- Other nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of Seren Innovations Inc., NRG Energy, Inc., e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all sold in 2006 or earlier.

See Note 4 to the consolidated financial statements for a further discussion of discontinued operations.

Contribution to Earnings (Millions of Dollars)	Three months ended March 31, 2008	Three months ended March 31, 2007
GAAP income		
Regulated electric utility income continuing operations	$ 93.1	$ 72.1
Regulated natural gas utility income continuing operations	67.6	56.9
Other utility results	9.7	10.4
Utility segment income continuing operations	170.4	139.4
Holding company costs and other results	(16.4)	(20.9)
Income continuing operations	154.0	118.5
Income (loss) discontinued operations	(0.9)	1.2
Total GAAP income	$ 153.1	$ 119.7

	Three months ended March 31, 2008	Three months ended March 31, 2007
GAAP earnings per share contribution		
Regulated electric utility continuing operations	$ 0.21	$ 0.17
Regulated natural gas utility continuing operations	0.16	0.13
Other utility results	0.02	0.02
Utility segment earnings per share continuing operations	0.39	0.32
Holding company costs and other results	(0.04)	(0.04)
Total GAAP earnings per share diluted	$ 0.35	$ 0.28

The following table summarizes significant components contributing to the changes in the first quarter of 2008 diluted earnings per share compared with the same period in 2007, which are discussed in more detail later.

Increase (decrease)	Three months ended March 31,
2007 ongoing earnings per share	**$ 0.27**
PSRI earnings	0.01
2007 GAAP earnings per share	**0.28**
Components of Change 2008 vs. 2007	
Higher base electric utility margins	0.07
Higher natural gas margins	0.03
Higher interest and other income	0.01
Higher operating and maintenance expense	(0.02)
Higher effective tax rate	(0.02)
Higher depreciation and amortization	(0.01)
Other	0.01
2008 GAAP earnings per share	**$ 0.35**

During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. Excluding the impact of the COLI program, Xcel Energy s ongoing first quarter 2008 earnings were $155 million, or $0.35 per share, compared with first quarter 2007 ongoing earnings of $114 million, or $0.27 per share. The following table provides a reconciliation of GAAP earnings per share to ongoing earnings per share for 2008 and 2007.

(Millions of Dollars)	Three Months ended March 31, 2008	2007
Ongoing earnings	$ 155.3	$ 113.5
PSRI earnings (loss)	(1.3)	5.0
Total continuing operations	154.0	118.5
Discontinued operations	(0.9)	1.2
Total GAAP earnings	$ 153.1	$ 119.7

	Three Months ended March 31, 2008	2007
Ongoing earnings per share	$ 0.35	$ 0.27
PSRI earnings		0.01
Total GAAP earnings per share	$ 0.35	$ 0.28

As a result of the termination of the COLI program, Xcel Energy s management believes that ongoing earnings provide a more meaningful comparison of earnings results between different periods in which the COLI program was in place and is more representative of Xcel Energy s fundamental core earnings power. Xcel Energy s management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the board of directors, in determining whether performance targets are met for performance-based compensation and when communicating its earnings outlook to analysts and investors.

Utility Results

Higher first quarter 2008 earnings were primarily attributable to higher electric and natural gas margins, reflecting various rate increases, weather-normalized retail sales growth, higher rider recovery, the impact of favorable temperatures and leap year, which increased sales. Partially offsetting these positive factors were higher operating and maintenance expense and increased depreciation expense.

The following summarizes the estimated impact of weather on regulated utility earnings per share, based on estimated temperature variations from historical averages (excluding the impact on commodity trading operations):

	Three months ended March 31,		
	2008 vs. Normal	2007 vs. Normal	2008 vs. 2007
Retail electric	$ 0.01	$ 0.01	$ 0.00
Firm natural gas	0.01	0.00	0.01
Total	$ 0.02	$ 0.01	$ 0.01

Other Results Holding Company and Other Costs

Financing Costs and Preferred Dividends Holding company results include interest expense and preferred dividend costs, which are incurred at the Xcel Energy and intermediate holding company levels and are not directly assigned to individual subsidiaries.

Discontinued Operations

All Other Seren Innovations Inc., NRG, e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all sold in 2006 or earlier, have activity reflected on Xcel Energy s financial statements.

Income Statement Analysis First Quarter 2008 vs. First Quarter 2007

Electric Utility, Short-Term Wholesale and Commodity Trading Margins

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

Xcel Energy has two distinct forms of wholesale sales: short-term wholesale and commodity trading. Short-term wholesale refers to energy-related purchase and sales activity, and the use of financial instruments associated with the fuel required for, and energy produced from, Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Commodity trading is not associated with Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Short-term wholesale and commodity trading activities are considered part of the electric utility segment.

Short-term wholesale and commodity trading margins reflect the estimated impact of regulatory sharing of margins, if applicable. Commodity trading revenues are reported net of related costs (i.e., on a margin basis) in the consolidated statements of income. Commodity trading expenses include purchased power, transmission, broker fees and other related costs.

The following table details the revenues and margin for base electric utility, short-term wholesale and commodity trading activities.

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Three months ended March 31, 2008				
Electric utility revenues (excluding commodity trading)	$ 1,906	$ 64	$	$ 1,970
Electric fuel and purchased power-utility	(1,031)	(57)		(1,088)
Commodity trading revenues			26	26
Commodity trading expenses			(23)	(23)
Gross margin before operating expenses	$ 875	$ 7	$ 3	$ 885
Margin as a percentage of revenues	45.9%	10.9%	11.5%	44.3%
Three months ended March 31, 2007				
Electric utility revenues (excluding commodity trading)	$ 1,752	$ 59	$	$ 1,811
Electric fuel and purchased power-utility	(926)	(54)		(980)
Commodity trading revenues			77	77
Commodity trading expenses			(72)	(72)
Gross margin before operating expenses	$ 826	$ 5	$ 5	$ 836
Margin as a percentage of revenues	47.1%	8.5%	6.5%	44.3%

The following summarizes the components of the changes in base electric utility revenues and base electric utility margin for the three months ended March 31:

Base Electric Utility Revenue

(Millions of Dollars)		2008 vs. 2007
Fuel and purchased power cost recovery	$	92
Conservation and non-fuel riders		11
Retail rate increases (Wisconsin and North Dakota interim)		10
Sales growth (excluding weather impact)		10
Increased revenue due to leap year (weather normalized impact)		9
Metropolitan Emissions Reduction Project (MERP) rider		5
Transmission revenue		5
Estimated impact of weather		3
SPS regulatory accruals		2
Other, including transmission revenue and sales mix		7
Total increase in base electric utility revenues	$	154

Base Electric Utility Margin

(Millions of Dollars)		2008 vs. 2007
Sales growth (excluding weather impact)	$	10
Retail rate increases (Wisconsin and North Dakota interim)		10
Increased margin due to leap year (weather normalized impact)		9
Conservation and non-fuel riders (partially offset in operating and maintenance expense)		8
MERP rider		5
Estimated impact of weather		3
Other, including transmission revenue, regulatory accruals and sales mix		4
Total increase in base electric utility margin	$	49

Natural Gas Utility Margins

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

(Millions of Dollars)	Three months ended March 31, 2008		2007	
Natural gas utility revenues	$	1,034	$	927
Cost of natural gas purchased and transported		(823)		(741)
Natural gas utility margin	$	211	$	186

The following summarizes the components of the changes in natural gas revenues and margin for the three months ended March 31:

Natural Gas Revenue

(Millions of Dollars)		2008 vs. 2007
Purchased natural gas adjustment clause recovery	$	81
Base rate increases (Colorado and Wisconsin)		15
Estimated impact of weather		3
Conservation revenue		3
Transportation		2
Sales growth (excluding weather impact)		1
Increased revenue due to leap year (weather normalized impact)		1
Other		1
Total increase in natural gas revenues	$	107

Natural Gas Margin

(Millions of Dollars)		2008 vs. 2007
Base rate changes (Colorado and Wisconsin)	$	15
Estimated impact of weather		3

Conservation revenue		3
Transportation		2
Sales growth (excluding weather impact)		1
Increased margin due to leap year (weather normalized impact)		1
Total increase in natural gas margin	$	25

Non-Fuel Operating Expense and Other Items

Other operating and maintenance expenses Other operating and maintenance expenses for the first quarter of 2008 increased by approximately $15 million, or 3.3 percent, compared with the same period in 2007. For more information, see the following table:

(Millions of Dollars)		Three months ended March 31, 2008 vs. 2007
Lower employee benefit costs	$	(9)
Higher combustion/hydro plant costs		8
Higher conservation incentive programs (offset in electric margins)		6
Higher contract labor and consulting costs		6
Higher nuclear plant outage costs		6
Higher labor costs		2
Lower nuclear plant operation costs		(2)
Other		(2)
Total increase in other operating and maintenance expense	$	15

Improved employee health care experience and a change to a high deductible health care plan, as well as lower current period performance based incentive plan expense, were the primary factors contributing to the lower employee benefit costs. The higher combustion/hydro plant costs were primarily attributable to normally scheduled and unplanned maintenance.

Depreciation and amortization Depreciation and amortization expense increased by approximately $6 million, or 2.8 percent, for the first quarter of 2008, compared with the first quarter of 2007. The increase is primarily due to normal system expansion, which was partially offset by the MPUC approval of NSP-Minnesota s remaining lives depreciation filing in the third quarter of 2007. This decision reduced third quarter depreciation retroactive to Jan. 1, 2007; however, it did not impact first quarter 2007 depreciation expense due to the approval in the third quarter of 2007.

Interest and other income, net Interest and other income increased by $8 million for the first quarter of 2008, compared with the same period in 2007. The increase is primarily the result of PSRI terminating the COLI program in 2007.

Allowance for funds used during construction, equity and debt (AFDC) AFDC increased by approximately $9 million, or 60.6 percent, for the first quarter of 2008 when compared with the same period in 2007. The increase was due primarily to the construction of Comanche 3.

Income taxes Income taxes for continuing operations increased by $29 million for the first quarter of 2008, compared with the same period in 2007. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 33.2 percent for the first quarter of 2008, compared with 28.8 percent for the same period in 2007. The higher effective tax rate for first quarter 2008 was primarily due to an increase in the forecasted annual effective tax rate for 2008, compared with 2007, largely as a result of PSRI terminating the COLI program in 2007.

Factors Affecting Results of Continuing Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs at Factors Affecting Results of Continuing Operations in Xcel Energy s Annual Report on Form 10-K filed for the year ended Dec. 31, 2007.

Regulation

Summary of Recent Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy s utility subsidiaries. State and local agencies have jurisdiction over many of Xcel Energy s utility activities, including regulation of retail rates and environmental mattersSee additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007. In addition to the matters discussed below, see Note 6 to the consolidated financial statements for a discussion of other regulatory matters.

Other Regulatory Matters **NSP-Minnesota**

Excelsior Energy Inc. (Excelsior) In December 2005, Excelsior, an independent energy developer, filed a power purchase agreement with the MPUC seeking a declaration that NSP-Minnesota be compelled to enter into an agreement to purchase the output from two integrated gas combined cycle (IGCC) plants to be located in northern Minnesota as part of the Mesaba Energy Project. Excelsior filed this petition making claims pursuant to Minnesota statutes relating to an Innovative Energy Project and Clean Energy Technology. NSP-Minnesota opposed the petition.

The MPUC referred this matter to a contested case hearing before an ALJ to act on Excelsior s petition. The contested case proceeding considered a 600 MW unit in phase I and a second 600 MW unit in phase II of the Mesaba Energy Project.

The MPUC issued its order for phase 1 of the hearing on Aug. 30, 2007. In it, the MPUC found that:

- The Mesaba Energy Project is an innovative energy project under the applicable statute;
- The terms and conditions of the proposed purchase power agreement are inconsistent with the public interest and are denied;
- Excelsior and NSP-Minnesota should resume negotiations towards an acceptable purchase power agreement, with assistance from the Minnesota Department of Commerce (MDOC) and the guidance provided by the order; and
- The MPUC will explore a statewide market for the output of this project.

The MPUC denied rehearing, except for certain clarifications and requiring status reports on negotiations. Excelsior appealed the MPUC s decision in December 2007. The Minnesota Court of Appeals dismissed the appeal as premature because the MPUC s order on phase I is not final agency action on the entire case.

Meanwhile, the ALJ issued a decision in Phase 2 of this proceeding, recommending denial of Excelsior s proposed purchase power agreement for a second IGCC project. Exceptions and replies have been filed.

Excelsior subsequently requested that the MPUC suspend consideration of phase 2, but the MPUC denied this request on April 10, 2008. The MPUC is expected to consider phase 2 at the hearing in the second quarter of 2008. At the April 10, 2008 hearing, the MPUC granted Excelsior s request for a finding that transmission facilities required for its proposed projects are exempt from Minnesota s certificate of need requirements. Several parties had opposed this request or asked the MPUC to defer a decision until after the phase 2 decision.

NSP System Resource Plan In December 2007, NSP-Minnesota filed its 2007 resource plan with the MPUC. The plan incorporates the actions needed to comply with expansive new legislation regarding greenhouse gas (GHG) emissions control, renewable energy procurement, and DSM adopted by the 2007 Minnesota legislature. Due to the expansion of wind generation procurement and DSM obligations, the plan indicates that the type of incremental resources has changed from prior plans. Key highlights of the plan include:

- Additional wind generation resources of 2,600 MW, allowing NSP-Minnesota to comply with our RES of 30 percent renewable energy by 2020.
- Increases in DSM of approximately 30 percent energy savings and 50 percent demand savings.
- Seek license renewals for Prairie Island s two units through 2033 and 2034, respectively, and expand capacity at Prairie Island by 160 MW and Monticello by 71 MW.
- Request approval to make environmental upgrades at Sherco, while expanding capacity by 80 MW. The environmental upgrades would result in a significant reduction in overall SO_2, NOx and mercury emissions from the facility.
- Negotiate and seek approval of purchases from Manitoba Hydro Electric Board (Manitoba Hydro) for 375 MW of intermediate and 350 MW of peaking resources beginning in 2015.
- Incremental peaking and intermediate generation needs of 2,300 MWs.
- Carbon emission reductions of 22 percent below 2005 levels by 2020, a six million ton reduction.

The MPUC established a comment period in NSP-Minnesota s pending Resource Plan proceeding, with initial comments due in April 2008 and reply comments due in June 2008.

NSP-Minnesota Base Load Acquisition Proceeding In November 2006, NSP-Minnesota filed a proposal with the MPUC for a purchase of 375 MW of capacity and energy from Manitoba Hydro for 2015-2025 and the purchase of 380 MW of wind energy to fulfill the base load need identified in the 2004 resource plan. An alternate supplier proposed a 375 MW share of a lignite coal generation plant to be located in North Dakota and 380 MW of wind energy generation, with an option for Xcel Energy ownership in both components. The MPUC referred the matter to a contested case proceeding.

In July 2007, NSP-Minnesota filed a petition asking to suspend the proceeding until NSP-Minnesota can complete its analysis of the impact of the RES and conservation goals on its need for additional resources, as outlined in the July 20, 2007 Notice of Changed Circumstance in the Resource Plan.

In December 2007, NSP-Minnesota filed the 2007 resource plan, along with a proposal for closing this proceeding as the new plan does not indicate a base load resource need. In March 2008, the MPUC approved the request to close this proceeding.

Nuclear Plant Power Uprates and Life Extension NSP-Minnesota is pursuing life extensions and capacity increases of all three of its nuclear units that will total approximately 235 MW, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2 s original steam generators, currently planned for replacement during the refueling outage in 2013. Capital investments for life cycle management and power uprate activities through 2007 have totaled approximately $40 million. For the years 2008 through 2015, spending is estimated at $1.1 billion. NSP-Minnesota plans to seek approval for an alternative recovery mechanism from customers of its nuclear costs. NSP-Minnesota submitted the certificates of need for the Monticello uprate to the MPUC on Feb. 14, 2008, and will submit for the Prairie Island uprate in the near future.

In April 2008, NSP-Minnesota filed an application with the Nuclear Regulatory Commission (NRC) to extend the operating life of its two nuclear reactors at Prairie Island by 20 years. NSP-Minnesota is in the process of finalizing a certificate of need application to support the proposed license extensions. That application, which will be filed later in 2008 with the MPUC, will seek to increase the number of spent fuel storage containers at Prairie Island to support the license extensions. The operating life of the Monticello nuclear plant has already been extended through 2030.

Other Regulatory Matters PSCo

Renewable Energy Standard The 2007 Colorado legislature adopted an increased RES that requires PSCo to generate or cause to be generated electricity from renewable resources equaling:

- At least 10 percent of its retail sales by 2010,
- 15 percent of retail sales by 2015 and
- 20 percent of retail sales by 2020.
- 4 percent must be generated from solar renewable resources with half the solar resources being located at customers facilities.

The new law limits the net incremental retail rate impact from these renewable resource acquisitions as compared to non-renewable resources to 2 percent. The new legislation encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a forward rider mechanism.

Colorado Climate Action Plan In November 2007, Governor Ritter of Colorado published a Colorado Climate Action Plan, which calls for a reduction in GHG emissions of 20 percent by 2020 with additional reductions by 2050.

PSCo Regulatory Policy Initiative At its March 2008 open meetings, the CPUC both discussed and voted to open an investigatory docket that will review the current regulatory structure to determine if current utility incentives are aligned with state public policy objectives and to determine if the existing structure is internally consistent in achieving these objectives. The CPUC expects to explore alternative forms of ratemaking for utilities and to better understand the state of the art on different mechanisms across the nation. An official order has not yet been issued.

Other Regulatory Matters SPS

Performance-Based Regulation and Quality of Service Requirements In Texas, SPS is subject to a quality of service plan requiring SPS to comply with electric service reliability performance targets. In January 2008, the PUCT staff served SPS with notice that it had initiated an investigation to determine whether SPS is in compliance with the Texas Statutes and PUCT rules on reliability and continuity of service. If SPS is found not to be in compliance, the PUCT may initiate an enforcement action and impose administrative penalties up to $25,000 per day.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters at Note 7 to the consolidated financial statements.

Critical Accounting Policies

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which all may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed. Item 7, Management s Discussion and Analysis, in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, includes a discussion of accounting policies that are most significant to the portrayal of Xcel Energy s financial condition and results, and that require management s most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Pending Accounting Changes

See a discussion of recently issued accounting pronouncements pending accounting changes at Note 2 to the consolidated financial statements.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy and its subsidiaries are exposed to a variety of market risks as disclosed in Management s Discussion and Analysis in its Annual Report on Form 10-K for the year ended Dec. 31, 2007. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. At March 31, 2008, there were no material changes to the market risks that affect the quantitative and qualitative disclosures presented as of Dec. 31, 2007, in Item 7A of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007. Commodity trading and Value-at-risk information is provided below for informational purposes.

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

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

The fair value of the commodity trading contracts at March 31, 2008 were as follows:

(Millions of Dollars)	Three months ended March 31, 2008	2007
Fair value of commodity trading contracts outstanding at Jan. 1	$ 6.3	$ (1.2)
Contracts realized or settled during the period	(3.8)	(10.7)
Fair value of commodity trading contract additions and changes during the period	1.4	13.2
Fair value of commodity trading contracts outstanding at March 31	$ 3.9	$ 1.3

As of March 31, 2008, fair values by source for the commodity trading net asset or liability balances were as follows:

(Thousands of Dollars)	Source of Fair Value	Futures/Forwards Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 67	$	$	$	$ 67
	2	900	1,230			2,130
PSCo	1	(552)				(552)
	2	2,137	411			2,548
Total Futures/Forwards Fair Value		$ 2,552	$ 1,641	$	$	$ 4,193

(Thousands of Dollars)	Source of Fair Value	Options Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP - Minnesota	2	$ (321)	$	$	$	$ (321)
Total Options Fair Value		$ (321)	$	$	$	$ (321)

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(1) Prices actively quoted or based on actively quoted prices.

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

Normal purchases and sales transactions, as defined by SFAS No. 133, hedge transactions and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not recorded at fair value as part of commodity trading operations.

At March 31, 2008, a 10-percent increase in market prices over the next 12 months for commodity trading contracts would have an immaterial impact on pretax income from continuing operations, whereas a 10-percent decrease would decrease pretax income from continuing operations by approximately $0.3 million.

Xcel Energy s short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value-at-risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movements, lognormal price distribution assumption, delta half-gamma approach for non-linear instruments and a three-day holding period for both electricity and natural gas.

VaR is calculated on a consolidated basis. The VaRs for the commodity trading operations were:

(Millions of Dollars)	Period Ended March 31, 2008	Change from Period Ended	VaR Limit	Average	High	Low

Dec. 31, 2007						
Commodity Trading (a)	$ 0.22	$ (0.04)	$ 5.00	$ 0.15	$ 0.38	$ 0.01

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

Interest Rate Risk

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

At March 31, 2008, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $8.4 million annually, or approximately $2.1 million per quarter. See Note 10 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries interest rate derivatives.

NSP Minnesota maintains trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At March 31, 2008, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk

Xcel Energy and its subsidiaries are exposed to credit risk. Credit risk relates to the risk of loss resulting from the nonperformance by a counterparty of its contractual obligations. Xcel Energy and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

Xcel Energy and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

At March 31, 2008, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $13.8 million, while a decrease of 10-percent would have resulted in a decrease of $13.7 million.

Observability of Fair Value Measurements

Xcel Energy adopted SFAS No. 157 on Jan. 1, 2008. SFAS No. 157 establishes a hierarchy for inputs used in measuring fair value, and requires that the most observable inputs available be used for fair value measurements. Note 11 to the consolidated financial statements describes the SFAS No. 157 fair value hierarchy, and discloses the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives - Commodity derivatives assets and liabilities assigned to Level 3 consist primarily of long-term forwards, long-term options and financial transmission rights. Level 3 commodity derivative assets and liabilities represent approximately 2 percent and 50 percent of total assets and liabilities, respectively, measured at fair value at March 31, 2008.

Determining the fair value of a financial transmission right (FTR) requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management s forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities include $12.2 million and $1.2 million of estimated fair values, respectively, for FTRs held at March 31, 2008.

Determining the fair value of long-term commodity forwards and options can require making forward price and volatility forecasts that extend to periods beyond those readily observable on active exchanges or quoted by brokers. Therefore, Xcel Energy must often use subjective and less observable long-term commodity price and volatility forecasts prepared by management for the long-term portions of these instruments. When these less observable long-term forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivatives assets and liabilities include $15.5 million and $11.1 million of estimated fair values, respectively, for commodity forwards and options held at March 31, 2008.

Nuclear Decommissioning Fund - Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities, however, less observable and subjective risk-based adjustments to estimated yield and forecasted prepayments are often significant to these valuations. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $97.2 million in the nuclear decommissioning fund at March 31, 2008 (approximately 8 percent of total assets measured at fair value), are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	**Three months ended March 31, 2008**		**2007**	
Cash provided by (used in) operating activities				
Continuing operations	$	575	$	583
Discontinued operations		(26)		16
Total	$	549	$	599

Cash provided by operating activities for continuing operations decreased by $8 million for the first three months of 2008, compared with the first three months of 2007. This decrease was due to the timing of working capital activity.

(Millions of Dollars)	**Three months ended March 31, 2008**		**2007**	
Cash used in investing activities				
Continuing operations	$	(508)	$	(478)
Total	$	(508)	$	(478)

Cash used in investing activities for continuing operations increased by $30 million for the first three months of 2008, compared with the first three months of 2007. The increase was due to increased capital expenditures and an investment in the WYCO pipeline and storage project.

(Millions of Dollars)	**Three months ended March 31, 2008**		**2007**	
Cash provided by (used in) financing activities				
Continuing operations	$	83	$	(85)
Total	$	83	$	(85)

Cash provided by financing activities for continuing operations increased by $168 million for the first three months of 2008, compared with the first three months of 2007. The increase was largely due to the issuance of $400 million of junior notes and $500 million of first mortgage bonds in the first quarter of 2008.

Capital Sources

Xcel Energy and Utility Subsidiary Credit Facilities As of April 28, 2008, Xcel Energy had the following credit facilities available to meet its liquidity needs:

(Millions of Dollars) Company	Facility	Drawn*	Available	Cash	Liquidity	Maturity
NSP-Minnesota	$ 500	$ 6.0	$ 494.0	$ 9.0	$ 503.0	December 2011
PSCo	700	197.1	502.9	0.2	503.1	December 2011
SPS	250	146.1	103.9	0.8	104.7	December 2011
Xcel Energy Holding Company	800	149.2	650.8	0.1	650.9	December 2011
Total	$ 2,250	$ 498.4	$ 1,751.6	$ 10.1	$ 1,761.7	

* Includes direct borrowings, outstanding commercial paper and letters of credit

The liquidity table reflects the payment of common dividends on April 21, 2008.

Short-Term Funding Sources Short-term borrowing, as a source of funding, is affected by regulatory actions and access to reasonably priced capital markets. This access is dependent in part on credit agency reviews and ratings. The following ratings reflect the views of Moody s Investor Services, Inc. (Moody s), Standard & Poor s Ratings Services (Standard & Poor s), and Fitch Ratings (Fitch). A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. As of May 2, 2008, the following table represents the credit ratings assigned to various Xcel Energy companies:

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

Commercial Paper Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. All four commercial paper programs are rated A-2 by Standard & Poor s and P-2 by Moody s. The short-term credit ratings for Xcel Energy, PSCo and SPS are all rated F2, while NSP-Minnesota is rated F1 by Fitch.

As of March 31, 2008, the authorized level of the commercial paper programs for Xcel Energy, NSP-Minnesota, PSCo, and SPS was $800 million, $500 million, $700 million, and $250 million, respectively. The outstanding amount of commercial paper at March 31, 2008, was $377.9 million at a weighted average yield of 3.54 percent.

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

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

The borrowings or loans outstanding at March 31, 2008, and the short-term borrowing limits from the money pool are as follows:

	Borrowings (Loans)	Total Borrowing Limits
NSP-Minnesota	$ (171.3)	$ 250 million
PSCo	71.3	250 million
SPS	100.0	100 million

Registration Statements NSP-Wisconsin and SPS anticipate filing registration statements in the second quarter of 2008.

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

Lea Power Purchase Power Agreement Lea Power is a natural gas combined cycle 602MW plant currently being constructed near Hobbs, New Mexico. SPS is expected to start taking energy beginning in the summer of 2008 when Lea Power reaches commercial operations. On April 24, 2008, however, SPS sent Lea Power a notice of default related to its failure to meet two construction milestones. It is uncertain to what extent, if any, this failure will have on Lea Power s ability to begin commercial operations in the summer of 2008. The purchase power agreement, which was executed in 2006, provides for SPS to have exclusive rights to dispatch the facility. Xcel Energy is currently evaluating the accounting implications of this contract, including capital lease and/or consolidation requirements. Further, restructuring of the contract is being considered. In addition, Xcel Energy is also evaluating the three additional purchase power agreements expected to reach commercial operations in the second quarter of 2008.

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments primarily through internally generated funds. Xcel Energy expects the note holders to convert the $57.5 million principal balance of its Senior Convertible Notes due

Nov. 21, 2008, to common equity by the maturity date of the notes. Xcel Energy plans to issue commercial paper to meet short-term working capital requirements.

During 2008, Xcel Energy plans to issue debt securities. These financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors. Current debt financing plans include the following:

- PSCo plans to issue between $500-$600 million of long-term senior debt securities in the second half of 2008 to refinance a $300 million long-term debt maturity, to refinance outstanding commercial paper, to fund utility capital expenditures and to provide funds for general corporate purposes. PSCo plans to issue commercial paper to meet short-term working capital requirements.
- NSP-Wisconsin plans to issue up to $250 million of long-term senior debt securities in the second half of 2008 to refinance an $80 million long-term debt maturity, to repay outstanding short-term debt, to fund utility capital expenditures and to provide funds for general corporate purposes. NSP-Wisconsin plans to issue inter-company notes to NSP-Minnesota to meet short-term working capital requirements.

Earnings Guidance

Xcel Energy s 2008 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

	2008 Diluted Earnings Per Share Range
Utility operations	$ 1.61 - $1.71
Holding company financing costs and other	(0.16)
Xcel Energy earnings per share	**$ 1.45 - $1.55**

Key Assumptions for 2008:

- Normal weather patterns are experienced during the year.
- Various riders, associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, are expected to increase revenue by approximately $55 million to $65 million over 2007 levels.
- Reasonable regulatory outcomes in the New Mexico electric rate case, North Dakota electric rate case, the PSCo and SPS FERC wholesale electric rate cases and the interim rate recovery of capacity costs in the upcoming Texas electric rate case.
- No material incremental accruals related to the SPS regulatory proceedings.
- Weather-adjusted retail electric utility sales grow by approximately 1.8 percent to 2.2 percent.
- Weather-adjusted retail firm natural gas sales grow by approximately 0.0 percent to 1.0 percent.
- Short-term wholesale and commodity trading margins are within a range of $20 million to $30 million.
- Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $45 million to $55 million over 2007 levels. We expect regulatory recovery of approximately $11 million of the increase of capacity costs. Capacity costs at PSCo are recovered under the purchased capacity cost adjustment.
- Utility operating and maintenance expenses increase between 2 percent and 3 percent.
- Depreciation expense is projected to increase approximately $55 million to $65 million over 2007 levels.
- Interest expense increases approximately $20 million to $25 million over 2007 levels.
- Allowance for funds used during construction-equity increases approximately $35 million to $45 million over 2007 levels.
- An effective tax rate for continuing operations of approximately 32 percent to 35 percent.
- Average common stock and equivalents for diluted earnings per share calculations of approximately 438 million shares.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 2, Management s Discussion and Analysis Financial Market Risks.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of Xcel Energy s management, including the CEO and CFO, of the effectiveness of our disclosure controls and procedures, the CEO and CFO have concluded that Xcel Energy s disclosure controls and procedures are effective.

Internal Controls Over Financial Reporting

No change in Xcel Energy s internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy s internal control over financial reporting.

Part II OTHER INFORMATION

Item 1. Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. After consultation with legal counsel, Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters. See Notes 6 and 7 of the Consolidated Financial Statements in this Quarterly Report on Form 10-Q for further discussion of legal proceedings, including Regulatory Matters and Commitments and Contingent Liabilities, which are hereby incorporated by reference. Reference also is made to Item 3 and Notes 14 and 15 of Xcel Energy s consolidated financial statements in its Annual Report on Form 10-K filed for the year ended Dec. 31, 2007, for a description of certain legal proceedings presently pending.

Item 1A. Risk Factors

Xcel Energy s risk factors are documented in Item 1A of Part I of its 2007 Annual Report on Form 10-K, which is incorporated herein by reference. There have been no material changes to the risk factors.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of shares that May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2008 Jan. 31, 2008		N/A		
Feb. 1, 2008 Feb. 29, 2008		N/A		
March 1, 2008 March 31, 2008	8,391	$ 19.78		
Total	8,391			

The repurchase of shares noted in the table above was made pursuant to the Xcel Energy Executive Annual Incentive Award Plan. The shares were returned to Xcel Energy on behalf of some of the participants receiving an incentive award of common shares to effectuate the payment of federal and state income taxes on the award.

Item 6. Exhibits

The following Exhibits are filed with this report:

4.01	Junior Subordinated Indenture, dated as of Jan.1, 2008, by and between the Company and Wells Fargo Bank, National Association, as trustee (Exhibit 4.01 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.02	Supplemental Indenture No. 1, dated Jan. 16, 2008, by and between the Company and Wells Fargo Bank, National Association, as trustee (Exhibit 4.02 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.03	Replacement Capital Covenant, dated Jan. 16, 2008 (Exhibit 4.03 to Form 8-K (file no. 001-03034) dated Jan. 16, 2008).
4.04	Supplemental Indenture dated March 1, 2018 between Northern States Power Company and The Bank of New York Trust Company, N.A., as successor trustee (Exhibit 4.01 to Form 8-K (file no. 001-31387) dated March 11, 2008.
31.01	Principal Executive Officer s and Principal Financial Officer s certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.
(Registrant)

/s/ TERESA S. MADDEN
Teresa S. Madden
Vice President and Controller

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer

May 2, 2008