XCEL ENERGY INC
Form 10-Q
July 27, 2007

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 June 30, 2007

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 or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x Accelerated Filer o Non-Accelerated Filer o

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 July 24, 2007**
Common Stock, $2.50 par value	419,873,638 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 June 30, 2007	Three Months Ended June 30, 2006	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Operating revenues				
Electric utility	$ 1,919,695	$ 1,786,571	$ 3,735,498	$ 3,632,443
Natural gas utility	330,868	270,990	1,258,290	1,289,130
Nonregulated and other	16,729	16,312	37,166	40,404
Total operating revenues	2,267,292	2,073,873	5,030,954	4,961,977
Operating expenses				
Electric fuel and purchased power utility	1,031,899	951,214	2,011,470	1,945,909
Cost of natural gas sold and transported utility	219,574	168,822	960,356	1,019,247
Cost of sales nonregulated and other	3,702	4,437	9,727	12,667
Other operating and maintenance expenses utility	434,912	442,093	895,335	876,363
Other operating and maintenance expenses nonregulated	5,728	6,614	12,031	12,178
Depreciation and amortization	214,694	203,665	428,107	406,325
Taxes (other than income taxes)	66,236	71,325	144,411	149,859
Total operating expenses	1,976,745	1,848,170	4,461,437	4,422,548
Operating income	290,547	225,703	569,517	539,429
Interest and other income, net (see Note 10)	4,373	6,651	9,055	10,393
Allowance for funds used during construction - equity	8,695	4,668	16,271	8,452
Interest charges and financing costs				
Interest charges includes other financing costs of $5,343, $6,393, $11,594 and $12,605, respectively	125,672	119,208	252,975	238,582
Allowance for funds used during construction - debt	(8,442)	(7,509)	(15,648)	(13,882)
Total interest charges and financing costs	117,230	111,699	237,327	224,700
Income from continuing operations before income taxes	186,385	125,323	357,516	333,574
Income taxes	62,282	27,234	119,233	92,366
Income from continuing operations	124,103	98,089	238,283	241,208
Income (loss) from discontinued operations, net of tax (see Note 3)	(48,102)	186	(42,571)	8,365
Net income	76,001	98,275	195,712	249,573
Dividend requirements on preferred stock	1,060	1,060	2,120	2,120
Earnings available to common shareholders	$ 74,941	$ 97,215	$ 193,592	$ 247,453
Weighted average common shares outstanding (thousands)				
Basic	412,710	405,434	410,370	404,783
Diluted	432,861	429,099	432,471	428,349
Earnings per share basic				
Income from continuing operations	$ 0.30	$ 0.24	$ 0.58	$ 0.59

Income (loss) from discontinued operations		(0.12)				(0.11)		0.02
Earnings per share basic	$	0.18	$	0.24	$	0.47	$	0.61
Earnings per share diluted								
Income from continuing operations	$	0.29	$	0.24	$	0.56	$	0.58
Income (loss) from discontinued operations		(0.11)				(0.10)		0.02
Earnings per share diluted	$	0.18	$	0.24	$	0.46	$	0.60
Cash dividends declared per common share	$	0.23	$	0.22	$	0.45	$	0.44

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(Thousands of Dollars)

	Six Months Ended June 30, 2007	Six Months Ended June 30, 2006
Operating activities		
Net income	$ 195,712	$ 249,573
Remove loss (income) from discontinued operations	42,571	(8,365)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	444,673	422,695
Nuclear fuel amortization	23,636	22,395
Deferred income taxes	109,574	(45,091)
Amortization of investment tax credits	(4,855)	(4,902)
Allowance for equity funds used during construction	(16,271)	(8,452)
Undistributed equity in earnings of unconsolidated affiliates	(1,413)	(1,431)
Share-based compensation expense	9,677	11,806
Net realized and unrealized hedging and derivative transactions	3,682	(16,934)
Changes in operating assets and liabilities:		
Accounts receivable	38,443	249,574
Accrued unbilled revenues	(36,224)	215,336
Inventories	97,082	139,640
Recoverable purchased natural gas and electric energy costs	203,726	225,903
Other current assets	8,398	11,295
Accounts payable	(150,728)	(301,480)
Net regulatory assets and liabilities	(28,491)	(12,314)
Other current liabilities	(26,553)	(24,351)
Change in other noncurrent assets	(33,983)	(285)
Change in other noncurrent liabilities	32,082	11,107
Operating cash flows provided by discontinued operations	30,542	80,305
Net cash provided by operating activities	941,280	1,216,024
Investing activities		
Utility capital/construction expenditures	(978,651)	(733,187)
Allowance for equity funds used during construction	16,271	8,452
Purchase of investments in external decommissioning fund	(313,102)	(11,570)
Proceeds from the sale of investments in external decommissioning fund	291,406	14,083
Nonregulated capital expenditures and asset acquisitions	(301)	(433)
Change in restricted cash	4,470	2,132
Other investments	803	10,581
Investing cash flows provided by discontinued operations		42,377
Net cash used in investing activities	(979,104)	(667,565)
Financing activities		
Short-term borrowings net	(6,069)	(608,120)
Proceeds from issuance of long-term debt	344,063	882,877
Repayment of long-term debt, including reacquisition premiums	(102,064)	(570,426)
Early participation payments on debt exchange (see Note 8)	(4,859)	
Proceeds from issuance of common stock	7,683	3,628
Dividends paid	(183,702)	(175,939)
Net cash provided by (used in) financing activities	55,052	(467,980)
Net increase in cash and cash equivalents	17,228	80,479

Net increase (decrease) in cash and cash equivalents -discontinued operations		(15,855)		9,536
Cash and cash equivalents at beginning of year		37,458		71,382
Cash and cash equivalents at end of quarter	$	38,831	$	161,397
Supplemental disclosure of cash flow information:				
Cash paid for interest (net of amounts capitalized)	$	154,251	$	212,719
Cash paid for income taxes (net of refunds received)		7,007		(7,083)
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	38,115	$	47,345
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	37,569	$	37,095
Issuance of common stock for senior convertible notes		125,632		

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	June 30, 2007	Dec. 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 38,831	$ 37,458
Accounts receivable, net of allowance for bad debts of $36,990 and $36,689, respectively	808,041	816,093
Accrued unbilled revenues	550,524	514,300
Materials and supplies inventories	167,682	158,721
Fuel inventory	104,643	95,651
Natural gas inventories	136,783	251,818
Recoverable purchased natural gas and electric energy costs	54,874	258,600
Derivative instruments valuation	140,238	101,562
Prepayments and other	180,179	189,658
Current assets held for sale and related to discontinued operations	148,531	229,633
Total current assets	2,330,326	2,653,494
Property, plant and equipment, at cost:		
Electric utility plant	19,651,634	19,367,671
Natural gas utility plant	2,902,950	2,846,435
Common utility and other property	1,481,813	1,439,020
Construction work in progress	1,880,675	1,425,484
Total property, plant and equipment	25,917,072	25,078,610
Less accumulated depreciation	(9,983,843)	(9,670,104)
Nuclear fuel , net of accumulated amortization: $1,261,553 and $1,237,917, respectively	176,516	140,152
Net property, plant and equipment	16,109,745	15,548,658
Other assets:		
Nuclear decommissioning fund and other investments	1,363,916	1,271,362
Regulatory assets	1,093,586	1,189,145
Prepaid pension asset	642,727	586,712
Derivative instruments valuation	413,641	437,520
Other	131,109	135,746
Noncurrent assets held for sale and related to discontinued operations	203,380	162,586
Total other assets	3,848,359	3,783,071
Total assets	$ 22,288,430	$ 21,985,223
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 295,512	$ 336,411
Short-term debt	620,231	626,300
Accounts payable	932,956	1,100,600
Taxes accrued	185,842	271,691
Dividends payable	97,548	91,685
Derivative instruments valuation	77,882	83,944
Other	390,162	347,809
Current liabilities held for sale and related to discontinued operations	72,575	26,149
Total current liabilities	2,672,708	2,884,589
Deferred credits and other liabilities:		
Deferred income taxes	2,386,674	2,264,164
Deferred investment tax credits	116,739	121,594
Asset retirement obligations	1,401,699	1,361,951
Regulatory liabilities	1,392,365	1,364,657
Pension and employee benefit obligations	685,215	704,913
Derivative instruments valuation	451,918	483,077

Customer advances		300,898		302,168
Other liabilities		157,198		119,633
Noncurrent liabilities held for sale and related to discontinued operations		7,571		5,477
Total deferred credits and other liabilities		6,900,277		6,727,634
Minority interest in subsidiaries		736		1,560
Commitments and contingent liabilities (see Note 6)				
Capitalization:				
Long-term debt		6,614,813		6,449,638
Preferred stockholders equity - authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800		104,980		104,980
Common stockholders equity - authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: June 30, 2007 419,509,528; Dec. 31, 2006 407,296,907		5,994,916		5,816,822
Total liabilities and equity	$	22,288,430	$	21,985,223

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(UNAUDITED)

(Thousands)

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
	Shares	Par Value				
Three months ended June 30, 2007 and 2006						
Balance at March 31, 2006	405,087	$ 1,012,719	$ 3,994,628	$ 625,283	$ (114,039)	$ 5,518,591
Net income				98,275		98,275
Net derivative instrument fair value changes during the period, net of tax of $7,005 (see Note 9)					10,320	10,320
Unrealized gain - marketable securities, net of tax of $4					6	6
Comprehensive income for the period						108,601
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(90,235)		(90,235)
Issuances of common stock	473	1,182	7,459			8,641
Share-based compensation			10,712			10,712
Balance at June 30, 2006	405,560	$ 1,013,901	$ 4,012,799	$ 632,263	$ (103,713)	$ 5,555,250
Balance at March 31, 2007	408,861	$ 1,022,152	$ 4,061,586	$ 801,148	$ (16,635)	$ 5,868,251
Net income				76,001		76,001
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $104 (see Note 12)					406	406
Net derivative instrument fair value changes during the period, net of tax of $5,856 (see Note 9)					6,935	6,935
Comprehensive income for the period						83,342
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(96,486)		(96,486)
Issuances of common stock	10,649	26,622	109,166			135,788
Share-based compensation			5,081			5,081
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 779,603	$ (9,294)	$ 5,994,916

See Notes to Consolidated Financial Statements

6

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(UNAUDITED)

(Thousands)

	Common Stock Issued Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
Six months ended June 30, 2007 and 2006						
Balance at Dec. 31, 2005	403,387	$ 1,008,468	$ 3,956,710	$ 562,138	$ (132,061)	$ 5,395,255
Net income				249,573		249,573
Net derivative instrument fair value changes during the period, net of tax of $18,088 (see Note 9)					28,320	28,320
Unrealized gain - marketable securities, net of tax of $17					28	28
Comprehensive income for the period						277,921
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(177,328)		(177,328)
Issuances of common stock	2,173	5,433	35,290			40,723
Share-based compensation			20,799			20,799
Balance at June 30, 2006	405,560	$ 1,013,901	$ 4,012,799	$ 632,263	$ (103,713)	$ 5,555,250
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				195,712		195,712
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $229 (see Note 12)					893	893
Net derivative instrument fair value changes during the period, net of tax of $3,968 (see Note 9)					6,135	6,135
Unrealized gain - marketable securities, net of tax of $2					4	4
Comprehensive income for the period						202,744
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(187,445)		(187,445)
Issuances of common stock	12,213	30,532	121,428			151,960
Share-based compensation			10,748			10,748
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 779,603	$ (9,294)	$ 5,994,916

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 June 30, 2007, and Dec. 31, 2006; the results of its operations and changes in stockholders equity for the three and six months ended June 30, 2007 and 2006; and its cash flows for the six months ended June 30, 2007 and 2006. 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, 2006, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Income Taxes Consistent with prior periods and upon adoption of Financial Accounting Standard Board (***FASB) Interpretation No.*** 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 , Xcel Energy records interest and penalties related to income taxes as interest charges in the Consolidated Statements of Income.

Reclassifications Certain amounts in the Consolidated Statements of Cash Flows have been reclassified from prior-period presentation to conform to the 2007 presentation. The reclassifications reflect the presentation of unbilled revenues, recoverable purchased natural gas and electric energy costs and regulatory assets and liabilities and share-based compensation expense as separate items rather than components of other assets and other liabilities within net cash provided by operating activities. In addition, activity related to derivative transactions have been combined into net realized and unrealized hedging and derivative transactions. These reclassifications did not affect total net cash provided by (used in) operating, investing or financing activities within the Consolidated Statements of Cash Flows.

As a result of a settlement in principle and management s decision to surrender all corporate-owned life insurance (COLI) policies when the offer has been accepted in writing by the government, all the amounts related to PSR Investments, Inc. (PSRI) have been classified as discontinued operations. See Note 3 and 4 for additional disclosure related to discontinued operations and the proposed COLI settlement. Financial data for PSRI has been presented as discontinued operations as outlined below. The financial statements have been recast for all periods presented herein.

2. Recently Issued Accounting Pronouncements

Fair Value Measurements (Statement of Financial Accounting Standards (SFAS) 157) In September 2006, the FASB issued SFAS 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 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 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS 157 on its financial condition and results of operations and does not expect the impact of adoption to be material.

The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115 (SFAS 159) In February 2007, the FASB issued SFAS 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 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. Xcel Energy is evaluating the impact of SFAS 159 on its financial condition and results of operations and does not expect the impact of adoption to be material.

3. Discontinued Operations

A summary of the subsidiaries presented as discontinued operations is discussed below. Results of operations for divested businesses and the results of businesses held for sale are reported for all periods presented on a net basis as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale in 2007 and 2006 have been reclassified to assets and liabilities held for sale in the Consolidated Balance Sheets.

Assets held for sale are valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, management considered cash flow analyses, bids and offers related to those assets and businesses. Assets held for sale are not depreciated.

PSRI

PSRI, a wholly owned subsidiary of Public Service Company of Colorado (PSCo), owns and manages life insurance policies on some of PSCo s employees, known as COLI policies. On June 19, 2007, a settlement in principle was reached between Xcel Energy and the Internal Revenue Service (IRS) in regards to PSCo s COLI policies. As a result of the settlement in principle and management s decision to surrender the COLI policies when the offer has been accepted in writing by the government, all the amounts related to PSRI have been classified as discontinued operations. See Note 4 for additional disclosure related to the proposed COLI settlement.

Regulated Utility Segments

Cheyenne Light, Fuel and Power Company (Cheyenne), which was sold in 2005, had an impact on Xcel Energy s financial statements in 2006 relating to tax adjustments.

Nonregulated Subsidiaries All Other Segment

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)	PSRI	Utility Segments	All Other	Total
Three months ended June 30, 2007				
Operating revenues	$	$	$	$
Operating expense (income), interest and other income, net	47,623		(1,566)	46,057
Pretax (loss) income from discontinued operations	(47,623)		1,566	(46,057)
Income tax expense (benefit)	1,561	(2)	486	2,045
Net (loss) income from discontinued operations	$ (49,184)	$ 2	$ 1,080	$ (48,102)
Three months ended June 30, 2006				
Operating revenues	$	$	$ 2,009	$ 2,009

Operating expense (income), interest and other income, net		6,849		(30)		1,533		8,352
Pretax (loss) income from discontinued operations		(6,849)		30		476		(6,343)
Income tax expense (benefit)		(6,696)		15		152		(6,529)
Net (loss) income from discontinued operations	$	(153)	$	15	$	324	$	186

(Thousands of dollars)		PSRI		Utility Segments		All Other		Total
Six months ended June 30, 2007								
Operating revenues	$		$		$	36	$	36
Operating expense (income), interest and other income, net		52,331				(1,799)		50,532
Pretax (loss) income from discontinued operations		(52,331)				1,835		(50,496)
Income tax benefit		(7,481)		(2)		(442)		(7,925)
Net (loss) income from discontinued operations	$	(44,850)	$	2	$	2,277	$	(42,571)
Six months ended June 30, 2006								
Operating revenues	$		$		$	4,838	$	4,838
Operating expense (income), interest and other income, net		11,953		(18)		6,165		18,100
Pretax (loss) income from discontinued operations		(11,953)		18		(1,327)		(13,262)
Income tax benefit		(18,493)		(1,165)		(1,969)		(21,627)
Net income from discontinued operations	$	6,540	$	1,183	$	642	$	8,365

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

(Thousands of dollars)	June 30, 2007	Dec. 31, 2006
Cash	$ 9,874	$ 25,729
Accounts receivables, net	3,404	2,998
Deferred income tax benefits	113,538	160,456
Other current assets	21,715	40,450
Current assets held for sale and related to discontinued operations	$ 148,531	$ 229,633
Net property, plant and equipment	$ 44	$ 174
Deferred income tax benefits	159,855	152,133
Other noncurrent assets	43,481	10,279
Noncurrent assets held for sale and related to discontinued operations	$ 203,380	$ 162,586
Accounts payable	$ 3,864	$ 2,230
Other current liabilities	68,711	23,919
Current liabilities held for sale and related to discontinued operations	$ 72,575	$ 26,149
Other noncurrent liabilities	$ 7,571	$ 5,477
Noncurrent liabilities held for sale and related to discontinued operations	$ 7,571	$ 5,477

4. Income Taxes

COLI In April 2004, Xcel Energy filed a lawsuit against the U.S. government in the U.S. District Court for the District of Minnesota to establish its right to deduct the interest expense that had accrued during tax years 1993 and 1994 on policy loans related to its COLI policies that insured certain lives of PSCo employees. These policies are owned by PSRI, a wholly owned subsidiary of PSCo.

After Xcel Energy filed this suit, the IRS sent three statutory notices of deficiency of tax, penalty and interest for 1995 through 2002. Xcel Energy has filed U.S. Tax Court petitions challenging those notices. PSRI also continued to take deductions for interest expense on policy loans for subsequent years. The total exposure for the tax years in dispute and through 2007 is approximately $583 million, which includes income tax, interest and potential penalties.

On June 19, 2007, a settlement in principle was reached between Xcel Energy and representatives of the United States Government that would resolve this dispute. The terms of the proposed settlement are as follows:

Xcel Energy would pay the IRS $64.4 million (or approximately $56 million, net, after tax) in full settlement of all of the government s claims for additional taxes, interest and penalties relating to these COLI plans for tax years 1993-2007.

Xcel Energy would further agree to claim no additional deductions resulting from its COLI plans for any tax year after 2007 and to surrender its policies when the offer has been accepted in writing by the government.

The government would permit Xcel Energy to surrender these policies without incurring any tax liability on any gain from that surrender.

This settlement requires final approval from the IRS and the Department of Justice (DOJ). There is no guarantee that such approvals will be obtained.

Among other things, the settlement process requires Xcel Energy to submit a written settlement offer setting forth the basic terms and for the DOJ Tax Division and the IRS to review that offer before they decide to accept or reject it. Xcel Energy submitted this settlement offer to the government on July 2, 2007.

It is expected that a final decision on the settlement will be reached during Xcel Energy s third quarter of 2007.

The COLI case was set for trial on July 23, 2007. Because a settlement in principle has been reached, the court has removed this case from the trial calendar.

As a result of the settlement in principle and management s decision to surrender the COLI policies when the offer has been accepted in writing by the government, Xcel Energy reported earnings from PSRI and the settlement costs as discontinued operations in the second quarter of 2007. See Note 3 for additional disclosure related to discontinued operations.

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) In July 2006, the FASB issued Interpretation FIN 48. FIN 48 prescribes how a company should recognize, measure, present and disclose uncertain tax positions that the company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the more likely than not recognition threshold be recognized or continue to be recognized on its effective date. As required, Xcel Energy adopted FIN 48 as of Jan. 1, 2007 and the initial derecognition amounts were reported as a cumulative effect of a change in accounting principle. The cumulative effect of the change, which is reported as an adjustment to the beginning balance of retained earnings, was not material. Following implementation, the ongoing recognition of changes in measurement of uncertain tax positions will be reflected as a component of income tax expense.

Xcel Energy files a consolidated federal income tax return, 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.

Xcel Energy has been audited by the IRS through tax year 2003, with a limited exception for 2003 research tax credits. The IRS commenced an examination of Xcel Energy s federal income tax returns for 2004 and 2005 (and research credits for 2003) in the third quarter of 2006, and that examination is anticipated to be complete by March 31, 2008. As of June 30, 2007, the IRS had not proposed any material adjustments to tax years 2003 through 2005. The statute of limitations applicable to Xcel Energy s 2000 through 2002 federal income tax returns expired as of June 30, 2007.

As previously disclosed, Xcel Energy is currently in litigation with the federal government to establish its right to deduct interest expense on COLI policy loans incurred since 1993. Xcel Energy and the IRS have reached a settlement in principle regarding this litigation (see previous discussion of COLI).

Xcel Energy is also currently under examination by the state of Colorado for years 1993 through 1996 and 2000 through 2004, the state of Minnesota for years 1998 through 2000, and the state of Wisconsin for years 2002 through 2005. A Texas franchise tax audit for report years 2004 through 2006 will commence in July 2007. No material adjustments have been proposed as of June 30, 2007. As of June 30, 2007, 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-1993, Minnesota-1998, Texas-2002, and Wisconsin-2002.

The amount of unrecognized tax benefits was $47.3 million on Jan. 1, 2007 (including $4.7 million reported as discontinued operations) and $60.6 million (including $16.7 million reported as discontinued operations) on June 30, 2007. These amounts were offset against the tax benefits associated with net operating loss and tax credit carryovers of $43.2 million on Jan. 1, 2007 (including $30.7 million reported as discontinued operations) and $43.7 million on June 30, 2007 (including $34.5 million reported as discontinued operations).

Included in the unrecognized tax benefit balance for continuing operations was $12.7 million and $7.9 million of tax positions on Jan. 1, 2007 and June 30, 2007, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance for continuing operations included $29.9 million and $36.0 million of tax positions on Jan. 1, 2007 and June 30, 2007, 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 change in the unrecognized tax benefit balance for continuing operations from April 1, 2007 to June 30, 2007, was due to the addition of similar uncertain tax positions relating to second quarter activity, and the resolution of certain federal audit matters. Xcel Energy s amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the IRS and state audits progress. However, at this time due to the nature of the audit process, it is not reasonably possible to estimate a range of the possible change.

The change in the unrecognized tax benefit balance for discontinued operations from April 1, 2007 to June 30, 2007 was due to the proposed settlement of the COLI litigation. Xcel Energy s amount of unrecognized tax benefits for discontinued operations could significantly change in the next 12 months as the settlement of the COLI litigation is finalized. This is estimated to reduce the amount of unrecognized tax benefits by $12.4 million.

The interest expense liability related to unrecognized tax benefits on Jan. 1, 2007, was not material due to net operating loss and tax credit carryovers. The change in the interest expense liability from Jan. 1, 2007, to June 30, 2007, was an increase of $23.1 million (including $21.9 million reported as discontinued operations), primarily due to the proposed settlement of the COLI litigation. Penalties of $2.1 million, (reported entirely as discontinued operations), were accrued as of June 30, 2007 due to the proposed settlement of the COLI litigation.

5. Rate Matters

NSP-Minnesota

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

Midwest Independent Transmission System Operator, Inc. (MISO) Long-Term Transmission Pricing In October 2005, MISO filed a proposed change to its Transmission and Energy Markets Tariff (TEMT) to regionalize future cost recovery of certain high voltage transmission projects to be constructed for reliability improvements. The proposal, called the Regional Expansion Criteria Benefits phase I (RECB I) proposal, would recover 20 percent of eligible transmission costs from all transmission service customers in the MISO 15 state region, with 80 percent recovered on a sub-regional basis for projects 345 kilovolt (KV) and above. Projects above 100 KV but less than 345 KV will be recovered 100 percent on a subregional basis. The proposal would exclude certain projects that had been planned prior to the October 2005 filing, and would require new generators to fund 50 percent of the cost of network upgrades associated with their interconnection. In February 2006, the FERC generally approved the RECB I proposal, but set the 20 percent limitation on regionalization for additional proceedings. Various parties filed requests for rehearing. On Nov. 29, 2006, the FERC issued an order on rehearing upholding the February 2006 order and approving the 20 percent limitation. On Dec. 13, 2006, the Public Service Commission of Wisconsin (PSCW) filed an appeal of the RECB I order.

In addition, in October 2006, MISO filed additional changes to its TEMT to regionalize future recovery of certain transmission projects (345 KV and above) constructed to provide access to lower cost generation supplies. The filing, known as Regional Expansion Criteria Benefits phase II (RECB II), would provide regional recovery of 20 percent of the project costs and sub-regional recovery of 80 percent, based on a benefits analysis. MISO proposed that the RECB II tariff be effective April 1, 2007.

On March 15, 2007, the FERC issued orders separately upholding the Nov. 29, 2006 order, accepting the RECB I pricing proposal, and approving most aspects of the RECB II proposal. Various parties filed requests for rehearing of the RECB II order in April 2007. The requests are pending FERC action.

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 is required to file a successor rate methodology in August 2007, to be effective Feb. 1, 2008. On April 19, 2007, FERC issued an order overruling a 2006 initial decision by a FERC administrative law judge (ALJ) recommending regionalization of the cost of existing transmission facilities in the PJM Interconnection, Inc. (PJM), another Regional Transmission Organization (RTO). FERC ordered PJM to continue to license plate rates for existing facilities. As a result, MISO will not propose to regionalize the recovery of the costs of existing transmission facilities in the Aug. 1, 2007, filing. The March 15, 2007 FERC orders regarding RECB I and II also required MISO to re-examine the cost allocation for new reliability improvements and economic projects in the August 2007 compliance filing.

Proposals to regionalize transmission costs could shift the costs of Northern States Power Co., a Minnesota corporation (NSP-Minnesota) and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin) transmission investments to other MISO transmission service customers, but would also shift the costs of transmission investments of other participants in MISO to NSP-Minnesota and NSP-Wisconsin.

Revenue Sufficiency Guarantee Charges On April 25, 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 1, 2005. The RSG charges are collected from certain MISO customers and paid to others. On Oct. 26, 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 late November 2006, however, certain parties filed further requests for rehearing challenging the reversal regarding refunds and the effective date.

On March 15, 2007, the FERC issued orders separately denying rehearing of the Oct. 26, 2006, order and rejecting certain aspects of the MISO compliance filings submitted in November 2006. The FERC ordered MISO to submit a revised compliance filing. As of June 30, 2007, Xcel

Energy had a reserve of $1.9 million.

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

NSP-Minnesota Electric Rate Case In November 2005, NSP-Minnesota requested an electric rate increase of $168 million or 8.05 percent. This increase was based on a requested 11 percent return on common equity (ROE), a projected common equity to total capitalization ratio of 51.7 percent and a projected electric rate base of $3.2 billion. On Dec. 15, 2005, the MPUC authorized an interim rate increase of $147 million, subject to refund, which became effective on Jan. 1, 2006.

On Sept. 1, 2006, the MPUC issued a written order granting an electric revenue increase of approximately $131 million for 2006 based on an authorized ROE of 10.54 percent. The scheduled rate increase has been reduced in 2007 to $115 million to reflect the return of Flint Hills Resources, a large industrial customer, to the NSP-Minnesota system. The MPUC Order became effective in November 2006, and final rates were implemented on Feb. 1, 2007.

On March 13, 2007, a citizen intervenor submitted a brief asking that the Minnesota Court of Appeals remand to the MPUC with direction to determine the correct amount of income tax collected in rates but not paid to taxing authorities, order the refund or credit to ratepayers for taxes collected in rates but not paid, order the refund to ratepayers of the amount of interim rates collected in January and February of 2006 in violation of the previous merger order and provide other equitable relief. The citizen intervenor passed away on May 15, 2007. The estate has filed a request with the Minnesota Court of Appeals that the appeal continue with the estate listed as the appellant.

NSP-Minnesota Natural Gas Rate Case In November 2006, NSP-Minnesota filed a request with the MPUC to increase Minnesota natural gas rates by $18.5 million, which represents an increase of 2.4 percent. The request is based on 11.0 percent ROE, a projected equity ratio of 51.98 percent and a natural gas rate base of $439 million. Interim rates, subject to refund, were set at a $15.9 million increase and went into effect on Jan. 8, 2007.

On April 10, 2007, NSP-Minnesota filed its rebuttal testimony and revised its requested relief to $16.8 million. The revised request was caused primarily by an updated ROE estimate of 10.75 percent and an update to the sales forecast.

On April 24, 2007, the Minnesota Department of Commerce (MDOC) filed surrebuttal testimony recommending a rate increase of $10.9 million based on an updated ROE of 9.5 percent. The Office of Attorney General (OAG) filed surrebuttal testimony that continued to recommend a 9.26 percent ROE and made reference to the fact that Xcel Energy s consolidated taxes are significantly lower than those requested for recovery, but made no specific recommendations on this issue.

On July 26, 2007, the ALJ issued a recommended decision. While NSP-Minnesota is in the process of completing a detailed evaluation of the recommended decision, NSP-Minnesota believes it is generally consistent with the MDOC recommended annual revenue increase of approximately $10.9 million, based on ROE of 9.5 percent. The MPUC final order is expected in September 2007.

North Dakota Gas Rate Case In December 2006, NSP-Minnesota filed a request with the North Dakota Public Service Commission (NDPSC) to increase North Dakota natural gas rates by $2.8 million, an increase of 3.0 percent. The request is based on 11.3 percent return on equity, a projected equity ratio of 51.59 percent and a natural gas rate base of $46.6 million. Interim rates, subject to refund, were set at a $2.2 million increase and went into effect on Feb. 13, 2007. On April 24, 2007, NSP-Minnesota and the NDPSC staff filed a settlement agreement.

On June 13, 2007 the NDPSC approved a settlement agreement with final rates going into effect on July 1, 2007. The key provisions in the settlement include:

A $2.3 million annual revenue increase;

An authorized return on equity of 10.75 percent;

A residential natural gas base rate freeze until 2010 (exclusive of changes in purchased gas costs);

An earnings sharing mechanism, which will result in customer refunds should NSP-Minnesota s natural gas operations in North Dakota exceed its authorized ROE during 2007, 2008 or 2009; and

Fully decoupled residential rates.

MISO Day 2 Market Cost Recovery On Dec. 20, 2006, the MPUC issued an order ruling that NSP-Minnesota may recover all MISO Day 2 costs, except Schedules 16 and 17, through its FCA.

NSP-Minnesota is refunding Schedule 16 and 17 costs recovered through the FCA in 2005 ($2.2. million) to customers through the FCA in equal monthly installments beginning March 2007.

NSP-Minnesota is recovering 50 percent of Schedule 16 and 17 costs starting in 2006 in the final rates established in the 2005 electric rate case.

NSP-Minnesota is allowed to defer 100 percent of the Schedule 16 and 17 costs not included in rates for a three-year period before starting the amortization.

The MPUC ruling on Schedules 16 and 17 costs will have no impact on net income in 2007.

On April 9, 2007, the OAG filed an appeal of the MPUC order to the Minnesota Court of Appeals. NSP-Minnesota and the other affected utilities intervened in the appeal and will urge the court to uphold the MPUC order. The date for a court decision in the appeal is not known.

Transmission Cost Recovery In November 2006, the MPUC approved the replacement of the Renewable Cost Recovery (RCR) rider with a Transmission Cost Recovery (TCR) rider pursuant to 2005 legislation. The TCR mechanism would allow recovery of incremental transmission investments between rate cases.

On Oct. 27, 2006, NSP-Minnesota filed for approval of recovery of $14.7 million in 2007 under the TCR tariff. The RCR rate factors will remain in effect until the TCR factors are implemented. On March 8, 2007, the MPUC voted to approve the recommendation of the MDOC to allow recovery of $13.1 million in 2007, but ruled $1.6 million of costs should be allocated to wholesale transmission service customers. This ruling will reduce recovery in Minnesota electric rates by $1.6 million in 2007.

On Feb. 28, 2007, NSP-Minnesota filed for South Dakota Public Utilities Commission (SDPUC) approval of a Transmission Cost Recovery Rider (TCRR). NSP-Minnesota proposed to recover $0.8 million in transmission related costs outside a general rate case. The tariff proposal is now pending SDPUC action.

Fixed Bill Complaint In January 2007, the OAG filed a complaint with the MPUC regarding the fixed monthly gas payment programs of NSP-Minnesota and another unaffiliated natural gas utility. This program generally allows customers to elect a fixed monthly payment for natural gas service that will not change for one year regardless of changes in natural gas costs or consumption due to weather. The complaint seeks termination of the program or modification, and seeks interim relief that would allow customers to exit the program.

On July 16, 2007, the MPUC issued its order suspending the program until the MPUC determines it is in the public interest. Other terms of the order include: low income housing energy assistance program customers will be allowed to immediately exit the fixed monthly gas payment program retroactive to the start of the current program year without incurring an exit fee; NSP-Minnesota is directed to attempt to resolve all stranded cost issues with the OAG. If a settlement is not reached, NSP-Minnesota may submit a proposal to the MPUC for resolution; NSP-Minnesota must submit a revised tariff reflecting suspension of the program within 20 days of the order. Prior to issuance of the order, NSP-Minnesota determined that it could not reach a settlement with the OAG and filed its proposal to resolve the phase out of the program on July 6, 2007.

Mercury Cost Recovery On Dec. 29, 2006, NSP-Minnesota requested approval of a Mercury Emissions Reduction Rider tariff and associated rate adjustments. The request is designed to recover approximately $5.4 million during 2007 from Minnesota electric retail customers for costs associated with implementing both the mercury and other environmental improvement portions of the Mercury Emissions Reduction Act of 2006. The MDOC reviewed the filing and provided comments indicating that further action of an environmental improvement plan was required before this filing could be approved. NSP-Minnesota subsequently withdrew the filing and will continue accruing costs associated with our compliance with the 2006 Mercury Reduction Act in a deferred account for future recovery.

Annual Automatic Adjustment Report for 2005 On Sept. 2, 2006, NSP-Minnesota filed its annual automatic adjustment report for the period from July 1, 2005 through June 30, 2006, which is the basis for the MPUC review of charges that flow through the FCA mechanism. The MDOC filed comments on April 18, 2007 asserting that NSP-Minnesota had not demonstrated the reasonableness of its cost assignment of certain market energy charges from the MISO Day 2 market between daily sales of excess generation and native energy needs. The MDOC indicated that NSP-Minnesota should provide additional support for its methodology in its reply comments, which were filed on June 1, 2007. NSP-Minnesota argued the cost assignment is consistent with the methodology approved in both a 2000 MPUC investigation of FCA cost allocations and the Dec. 20, 2006 MPUC order authorizing FCA recovery of most MISO Day 2 charges. The 2006 annual automatic adjustment report is pending final MPUC action.

Annual Review of Remaining Lives Depreciation Filing On June 4, 2007, as part of its annual review of remaining lives depreciation filing, NSP-Minnesota recommended lengthening the life of the Monticello nuclear plant by 20 years retroactive to Jan. 1, 2007 as well as certain other smaller life adjustments. On July 9, 2007, the MDOC recommended approval of the longer lives and sought a small adjustment to rate base in future rate cases to reflect this change so close to NSP-Minnesota s last rate case. On July 19, NSP-Minnesota filed replies specifying the calculation of any potential future adjustment. Assuming the MPUC approves this filing, 2007 depreciation expense would decrease by approximately $31 million. The MPUC is expected to rule on this filing during the third quarter of 2007.

NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings FERC

Wholesale Rate Case Application On July 31, 2006, NSP-Wisconsin filed a rate case at the FERC requesting a base rate increase of approximately $4 million, or 15 percent, for its ten wholesale municipal electric sales customers. In February 2007, NSP-Wisconsin reached a settlement with customers that provides for full cost recovery of MISO Day 2 and renewable energy costs through the fuel cost adjustment clause and a $2.4 million base rate increase. On April 13, 2007, the settlement rate increase was approved on an interim basis, effective March 1, 2007. On June 7, 2007 the FERC issued a letter order approving the uncontested offer of settlement in the case.

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

Electric and Gas Rate Case ***On June 1, 2007, NSP-Wisconsin filed with the PSCW a request to increase retail electric rates by $67.4 million and retail natural gas rates by $5.3 million, representing overall increases of 14.3 percent and 3.3 percent, respectively. The request assumes a common equity ratio of 53.86*** percent, a return on equity of 11.00 percent and a combined electric and natural gas rate base of approximately $640 million***. The PSCW is expected to act upon the request during the fourth quarter of 2007 and new rates are expected to be implemented in early 2008.***

MISO Cost Recovery On June 29, 2006, the PSCW opened a proceeding to address the proper amount of MISO Day 2 deferrals that the state s utilities should be allowed to recover and the proper method of rate recovery.

On Sept. 1, 2006, NSP-Wisconsin detailed its calculation methodology and reported that, as of June 30, 2006, it had deferred approximately $6.2 million. PSCW staff and intervenors filed testimony in December 2006, arguing that the various methodologies used by the utilities to calculate the deferrals were inconsistent, and to varying degrees incorrect. Further, the testimony argued that some or all of the deferred costs are being recovered in current rates and were, therefore, inappropriately deferred and the utilities should be required to write off balances that were inappropriately deferred.

On June 15, 2007 the PSCW verbally approved NSP-Wisconsin s deferral methodology with two exceptions. The PSCW ruled that NSP-Wisconsin had incorrectly calculated the deferral associated with incremental transmission line losses in 2005, and with MISO s subsequent billing correction related to over collected losses. The PSCW also decided that the ultimate decision on the amount of deferred costs eligible for recovery would be addressed in each utility s next rate case and extended the authorization to defer MISO Day 2 costs through Dec. 31, 2007.

As of June 30, 2007, NSP-Wisconsin has deferred approximately $11.0 million, which includes carrying costs, associated with the deferral of MISO Day 2 costs.

Although a written order has not yet been issued in the MISO Cost Recovery docket, NSP-Wisconsin estimates the PSCW decisions in that case could reduce the amount of this deferral by as much as $5 million. Accordingly, NSP-Wisconsin has recognized a reserve of approximately $5 million to reflect potential disallowance of a portion of its deferral.

In the electric rate case filed June 1, 2007, NSP-Wisconsin requested recovery over a two year period of the MISO Day 2 charges and credits that were deferred from April 1, 2005 through Dec. 31, 2006 under previous PSCW orders.

Fuel Cost Recovery Rulemaking On June 22, 2006, the PSCW opened a rulemaking docket to address potential revisions to the electric fuel cost recovery rules. Wisconsin statutes prohibit the use of automatic adjustment clauses by large investor-owned electric public utilities. Instead, the statutes authorize the PSCW to approve, after a hearing, a rate increase for these utilities to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In opening this rulemaking, the PSCW recognized the increased volatility of fuel and energy costs. On Sept. 7, 2006, Wisconsin s large investor-owned utilities, including NSP-Wisconsin, jointly filed proposed revisions to the rules. The utilities proposal incorporates a plan year forecast and an after-the-fact reconciliation to eliminate regulatory lag, and ensure recovery of prudently incurred costs. On Nov. 3, 2006, a coalition of customer and intervenor groups submitted a counter proposal that included only minor revisions to the existing rules.

On May 3, 2007, the PSCW directed its staff to proceed with drafting revisions to the fuel rules. The PSCW requested modifications to incorporate a stronger incentive/penalty mechanism, provide customers more rate stability, increase the level of PSCW oversight, and minimize the administrative burden of the process on all parties Lastly, the PSCW directed the proposed rules be circulated to all parties for further review and comment. No timetable was set to issue the draft rule, although it is expected the first draft of the rules will be issued this summer. At this time it is not certain what changes to the existing rules will be recommended by the PSCW.

PSCo

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

Natural Gas Rate Case On Dec. 1, 2006, PSCo filed with the CPUC, a request to increase natural gas rates by $41.9 million, representing an overall increase of 2.96 percent, primarily related to capital investments and rising operating costs. The request assumes a common equity ratio of 60.17 percent and a ROE of 11 percent. The jurisdictional rate base is approximately $1.1 billion.

On June 18, 2007, the CPUC approved a settlement between PSCo, the CPUC staff and the Colorado Office of Consumer Council (OCC), which granted the following:

An annual revenue increase of $32.3 million, based on a 10.25 percent return on equity and a 60.17 percent equity ratio.

The CPUC modified the partial decoupling mechanism to allow PSCo recovery of additional revenues in future years to compensate for the portion of the decline in weather normalized residential use per customer that exceeds the first 1.3 percent in decline in use (to be reflective of 50 percent of the historic average decline in use).

Under the terms of the agreement, parties to the settlement may seek reconsideration of the CPUC s order, however, PSCo does not plan to seek reconsideration.

SPS

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, wholesale cooperative customers of Southwestern Public Service Co., a New Mexico corporation (SPS), filed a rate complaint at the FERC. The complaint alleged that SPS rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustments contained in SPS wholesale rate schedules. Among other things, the complainants asserted that SPS was not properly calculating the fuel costs that are eligible for recovery to reflect fuel costs recovered from certain wholesale sales to other utilities, and that SPS had inappropriately allocated average fuel and purchased power costs to other of SPS wholesale customers, effectively raising the fuel costs charges to complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental) intervened in the proceeding.

On May 24, 2006, a FERC ALJ issued an initial recommended decision in the proceeding. The FERC will review the initial recommendation and issue a final order. SPS and others have filed exceptions to the ALJ s initial recommendation. The FERC s order may or may not follow any of the ALJ s recommendation. In the recommended decision, 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 allocating incremental fuel costs incurred by SPS in making wholesale sales of system firm capacity and associated energy to other firm customers at market-based rates during this period based on the view that such sales should be treated as opportunity sales.

SPS believes the ALJ erred on significant and material issues that contradict FERC policy or rules of law. Specifically, SPS believes, based on FERC rules and precedent, that it has appropriately applied its FCAC tariff to the proper classes of customers. These market-based sales were of a long-term duration under FERC precedent and were made from SPS entire system. Accordingly, SPS believes that the ALJ erred in concluding that these transactions were opportunity sales, which require the assignment of incremental costs.

The FERC has approved system average cost allocation treatment in previous filings by SPS for sales having similar service characteristics and previously accepted for filing certain of the challenged agreements with average fuel cost pricing.

Moreover, SPS believes that the ALJ s recommendation constituted a violation of the Filed Rate Doctrine in that it effectively results in a retroactive amendment to the SPS FERC-approved FCAC tariff provisions. Under existing regulations, the FERC may modify a previously approved FCAC on a prospective basis. Accordingly, SPS believes it has applied its FCAC correctly and has sought review of the recommended decision by the FERC by filing a brief on the exceptions.

While SPS believes it should ultimately prevail in this proceeding; however, if the FERC were to adopt the majority of the ALJ s recommendations, SPS refund exposure could be approximately $50 million, based on an evaluation of all sales made from Jan. 1, 1999 to Dec. 31, 2006. FERC action is pending. Additionally, SPS has entered into settlement discussions with the wholesale cooperative customers. As of June 30, 2007, based upon management s estimate of this potential liability, SPS believes the appropriate accrual has been recorded for this matter.

This case was on the July 19, 2007 FERC Open Meeting agenda. On July 17, 2007, Golden Spread and SPS filed a joint motion requesting the FERC to defer the final order for 60 days. The New Mexico cooperatives, Cap Rock and Occidental either supported the motion or did not oppose it. Public Service Company of New Mexico filed in opposition to the request. The FERC removed the case from the agenda. This provides additional time for settlement with all parties to the case.

Wholesale Power Base Rate Application On Dec. 1, 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. On Jan. 31, 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. The case is presently in the settlement judge procedures and an agreement in principle has been reached for base rates for the full-requirements customers and PNM. One other wholesale customer has not settled. On Sept. 7, 2006, the offer of settlement with respect to the full-requirements customer was filed for approval and on Sept. 19, 2006, the offer of settlement with respect to PNM was filed for approval. Subsequent to filing rebuttal testimony, on March 29, 2007, SPS and the remaining wholesale customer entered into settlement negotiations. The current hearing schedule has been postponed.

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

Texas Retail Base Rate And Fuel Reconciliation Case On May 31, 2006, SPS filed a Texas retail electric rate case requesting an increase in annual revenues of approximately $48 million. The rate filing was based on a historical test year, an electric rate base of $943 million, a requested ROE of 11.6 percent and a common equity ratio of 51.1 percent.

In addition, SPS submitted a fuel reconciliation filing, which requested approval of approximately $957 million of Texas-jurisdictional fuel and purchased power costs for 2004 through 2005. As a part of the fuel reconciliation case, fuel and purchased energy costs were reviewed.

On March 27, 2007, SPS and various intervenors filed a unanimous stipulation agreement related to the Texas retail rate case as well as the fuel reconciliation portion of the proceeding. The agreement includes the following terms:

The settlement provides for an annual base rate increase of $23 million, or approximately 3 percent.

The settlement is a black box agreement, with no stipulated ROE or capital structure.

The settlement disallows approximately $27 million of SPS 2004 and 2005 fuel expense.

An additional $2.3 million will be deducted from SPS next fuel reconciliation filing to be made in 2008, associated with the 2006-2007 fuel reconciliation period.

All of SPS existing long-term firm and interruptible capacity wholesale sales are assigned system average costs for purposes of Texas retail ratemaking, except for sales to El Paso Electric (EPE), which is determined by the PUCT separately.

The settlement also creates standards for cost assignment that would apply to future wholesale sale transactions, and establishes margin sharing of market based wholesale demand revenues.

If SPS files a general rate case in 2008, the settlement would allow for an interim rate increase associated with a purchased power agreement with Lea Power Partners of approximately $1.5 million per month from the date of commercial operations. Interim rates would be subject to a true-up based on the outcome of the rate case proceeding and actual capacity costs incurred.

An estimated settlement allowance and reserve was established in 2006 and prior periods, which approximated the settled amounts of previously deferred or recovered fuel expense.

On March 27, 2007, the ALJ approved SPS request to implement the $23 million base rate increase, effective April 2007, on an interim basis until the PUCT acts on the stipulation. The $23 million base rate increase includes approximately $14 million of coal cost that was previously recovered through the fuel cost recovery mechanism, and approximately $6.2 million that results from interruptible customers converting to firm service.

On July 27, 2007, the PUCT issued a written order adopting the settlement and assigning incremental costs to the EPE sale. The effect of this decision under the terms of the settlement is an additional $3 million in fuel costs assigned to EPE, which SPS will not recover either through its FCA or its contract. For 2008, this amount will reach $6.3 million. SPS has previously given notice to EPE to terminate the agreement based on a regulatory provision and Xcel Energy expects that the termination will be effective in 2009.

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

New Mexico Fuel Factor Continuation Filing On Aug. 18, 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 allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause.

On May 2, 2007, the hearing examiner issued his recommended decision in which he determined the following:

The NMPRC is barred from granting the retroactive refunds or financial penalties requested by the parties.

The issues related to the assignment of system average fuel cost to SPS firm wholesale sales, subsequent to March 7, 2006, should be litigated in SPS next rate case that will be filed this summer, or in a separate parallel proceeding with the results to be incorporated into the next rate case.

The NMPRC lacked legal authority to apply any change in cost assignment methodology retroactively until such date that SPS was put on notice of any concern with its longstanding assignment practice.

March 7, 2006 was the first time that SPS was put on notice with respect to any change in New Mexico s assignment practice.

The future litigation recommendation would determine both the proper allocation and assignment of fixed and fuel costs and examine the prudence of SPS firm wholesale contracts and affiliate transactions related to those wholesale sales.

Charges collected through the FPPCAC since March 7, 2006, should be subject to refund pending further order of the NMPRC. The hearing examiner also noted that specific allegations regarding affiliate transactions could also be resolved in these proceedings.

Under the recommended decision, SPS would also be ordered to refund approximately $1.6 million of long-term purchased power capacity costs that it acknowledged were erroneously collected through the FPPCAC. SPS would be authorized to continue its use of the FPPCAC pending a final order in the next rate case. The hearing examiner also determined that no action was required on renewable energy certificates and that SPS should seek a determination of proper treatment of SO2 allowances in a separate proceeding. Although there is no deadline for NMPRC action, SPS expects the NMPRC will act during the third quarter of 2007. As of June 30, 2007, based upon management s estimate of this potential liability, SPS believes the appropriate accrual has been recorded for this matter.

6. Commitments and Contingent Liabilities

Except to the extent noted below, the circumstances set forth in Notes 13, 14 and 15 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2006 and Notes 4 and 5 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.

Operating Leases In May 2007, PSCo commenced a purchased power agreement that is being accounted for as an operating lease in accordance with Emerging Issues Task Force 01-8, Determining Whether an Arrangement Contains a Lease. The 20-year agreement calls for capacity payments of $10.6 million, $16.1 million, $16.4 million $16.7 million, $17.1 million and $312.3 million for 2007, 2008, 2009, 2010, 2011 and thereafter, respectively.

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 or predecessors; 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.

To estimate the cost to remediate 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 June 30, 2007, the liability for the cost of remediating these sites was estimated to be $28.7 million, of which $3.0 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 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.

On Sept. 5, 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 late 2007 or 2008 following the submission of the remedial investigation report and feasibility study in 2007. 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) 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 field work for the demonstration study was completed in February 2007, and the EPA is scheduled to complete its assessment this summer. In 2006, NSP-Wisconsin spent $2.0 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.

The WDNR and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The EPA and WDNR have not yet selected the method of remediation to use at the site. 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 cost of remediating the Ashland site is not determinable. NSP-Wisconsin has recorded a liability of $25.0 million for its potential liability for remediating the Ashland site and for external legal and consultant costs. 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, using information available to date and reasonably effective remedial methods.

On Oct. 19, 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.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based upon 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 operate as a credit to ratepayers.

Fort Collins Manufactured Gas Plant Site Prior to 1926, Poudre Valley Gas Co., a predecessor of PSCo, operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the Poudre Valley Gas Co., PSCo shut down the MGP site and has sold most of the property. An oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. On Nov. 10, 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co., 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 May 2005, PSCo filed a natural gas rate case with the CPUC requesting recovery of cleanup costs at the Fort Collins MGP site spent through March 2005, which amounted to $6.2 million, to be amortized over four years. PSCo reached a settlement agreement with the parties in the case. The CPUC approved the settlement agreement on Jan. 19, 2006 and the final order became effective on Feb. 3, 2006, with rates effective Feb. 6, 2006.

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.

In April 2005, PSCo brought a contribution action against Schrader Oil Co. and related parties alleging Schrader Oil Co. 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. On Dec. 14, 2005, the court denied Schrader s request to dismiss the PSCo suit. On Jan. 3, 2006, Schrader 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 has alleged as part of its counterclaim an imminent and substantial endangerment of its property as defined by RCRA. In September 2006, PSCo filed a Motion For Partial Summary Judgment to dismiss Schrader s RCRA claim. PSCo believes the allegations with respect to PSCo are without merit and will vigorously defend itself.

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 14 to the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2006. 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.

Cunningham Station Groundwater Cunningham Station is a natural gas-fired power plant constructed in the 1960s by SPS and has 28 water wells installed on its water rights. The well field provides water for boiler makeup, cooling water and potable water. Following an acid release in 2002, groundwater samples revealed elevated concentrations of inorganic salt compounds not related to the release. The contamination was identified in wells located near the plant buildings. The source of contamination is thought to be leakage from ponds that receive blow down water from the plant.

In response to a request by the New Mexico Environment Department (NMED), SPS prepared a corrective action plan to address the groundwater contamination. Under the plan submitted to the NMED, SPS agreed to control leakage from the plant blow down ponds through construction of a new lined pond, additional irrigation areas to minimize percolation, and installation of additional wells to monitor groundwater quality. On June 23, 2005, NMED issued a letter approving the corrective action plan. The action plan was subject to continued compliance with New Mexico regulations and oversight by the NMED. The Cunningham wastewater management project has been completed at a final cost of $3.5 million. Upon completion of the project, NMED finalized the wastewater permit. SPS began the implementation of a similar process at the Maddox Station in 2007. The permitting process for Maddox Station has begun and is estimated to cost approximately $1.3 million through 2008 and will be capitalized or expensed as incurred.

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.

On July 11, 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.

On March 15, 2006, the EPA denied the petition for reconsideration. On June 27, 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. Court of Appeals. Pursuant to the court s scheduling order, briefing is expected to be finalized in September 2007.

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 with the installation of low NOx burners on Harrington 3 in 2006, there are capital investments estimated at $12 million remaining for NOx controls in the SPS region. Purchases of NOx allowances in the first phase are estimated at $1.4 million. Annual purchases of SO2 allowances are estimated in the range of $13 million to $25 million each year, beginning in 2012, for phase I, based on allowance costs and fuel quality as of March 2007.

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.

These cost estimates represent one potential scenario on complying with CAIR, if West Texas is not excluded. There is uncertainty concerning implementation of CAIR. States are required to develop implementation plans within 18 months of the issuance of the new rules and have a significant amount of discretion in the implementation details. Legal challenges to CAIR rules could alter their requirements and/or schedule. The uncertainty associated with the final CAIR rules makes it difficult to project the ultimate amount and timing of capital expenditures and operating expenses.

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.

Clean Air Mercury Rule In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from power plants for the first time. The EPA s CAMR uses a national cap-and-trade system, where compliance may be achieved by either adding mercury controls or purchasing allowances or a combination of both and is designed to achieve a 70 percent reduction in mercury emissions. It affects all coal- and oil-fired generating units across the country that are greater than 25 MW. Compliance with this rule occurs in two phases, with the first phase beginning in 2010 and the second phase in 2018. States will be allocated mercury allowances based on coal type and their baseline heat input relative to other states. Each electric generating unit will be allocated mercury allowances based on its percentage of total coal heat input for the state. Similar to the CAIR 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.

NSP-Minnesota currently estimates that it can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. Estimating the cost of compliance with CAMR is difficult because technologies specifically designed for control of mercury are in the early stages of development and there is no established market on which to base the cost of mercury allowances. NSP-Minnesota s preliminary analysis for phase I compliance suggests capital costs of approximately $22.7 million for the mercury control equipment and continuous monitoring equipment at the A.S. King, Sherburne County (Sherco) and Black Dog generating facilities. The analysis indicates increased operating and maintenance expenses of approximately $22.6 million, beginning in 2010. Additional costs will be incurred to meet phase II requirements in 2018.

Testing indicates that NSP-Wisconsin facilities will be low mass mercury emitters: therefore, compliance with CAMR is not expected to require mercury controls or purchases of allowances.

In February 2007, the Colorado Air Quality Control Commission passed a mercury rule. The rule was based on a negotiated rule that was agreed upon by participating environmental groups, utilities, local government coalitions, and the Colorado Air Pollution Control Division (CAPCD). The rule requires mercury emission controls capable of achieving 80 percent capture to be installed at Pawnee Station in 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 new rule and is currently unable to provide a capital cost estimate. The EPA has expressed concerns with allowance restrictions after reviewing the Colorado mercury rule.

In the SPS region, the Texas Commission on Environmental Quality (TCEQ) has adopted by reference the EPA model program. SPS continues to evaluate the strategy for complying with CAMR and estimates capital costs of $14.5 million and increased operating and maintenance expenses of approximately $7.9 million for mercury control equipment beginning in 2010.

Minnesota Mercury Legislation On May 2, 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 has installed, and will maintain and operate continuous mercury emission monitoring systems or other monitoring methods approved by the Minnesota Pollution Control Agency (MPCA). The information obtained will be used to establish a baseline from which to measure mercury emission reductions. Mercury emission reduction plans must 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 $22.7 to $280.2 million for the mercury control and continuous monitoring equipment, with increased operating and maintenance expenses estimated to range from approximately $22.6 to $48.4 million. The lower values include costs to achieve a 50 percent mercury reduction for Sherco units 1 and 2, beginning in 2010. The higher values include costs to try to achieve a 90 percent mercury reduction for Sherco units 1 and 2, beginning in 2010 and escalating to 2013. The lower cost estimates are also included above as part of the total cost estimate to comply with CAMR. 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. On Sept. 15, 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. On Jan. 11, 2007, the MPUC approved this request for deferred accounting with a cap of $6.3 million.

Regional Haze Rules On June 15, 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, NOx, and particulate matter emissions under BART and then set BART emissions limits for those facilities. On May 30, 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART technology or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. On Aug. 1, 2006, PSCo submitted its BART alternatives analysis to the CAPCD. As set forth in its analysis, 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. The CAPCD expects to finalize the regional haze state implementation plan in late 2007 for submittal to the EPA in 2008. BART emission controls associated with the plan must be installed within five years of EPA approval. On June 4, 2007, the CAPCD approved PSCo s BART analysis and requested public comment on its BART determination and PSCo s BART permits. The comment period expires July 28, 2007, after which the CAPCD will either grant, deny, or grant with conditions PSCo s BART permits.

NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 on Oct. 26, 2006. The 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.

Voluntary Capacity Upgrade and Emissions Reduction Filing On Jan. 2, 2007, NSP-Minnesota submitted a filing to the MPUC for a major emissions reduction project at Sherco Units 1, 2 and 3 to reduce emissions and expand capacity by installing NOx controls (low NOx burners, overfire air and Selective Catalytic Reduction), installing mercury control systems, replacing the wet scrubbers on units 1 and 2 with semi-dry scrubbers, retrofitting different sections of the turbines on all three units, replacing generators and other associated equipment on all three units, and installing additional cooling capacity. The projected cost of this project is approximately $905 million and encompasses the higher value mercury control costs discussed above in the Minnesota Mercury Legislation section. NSP-Minnesota s investments are subject to the MPUC approval of a cost recovery mechanism.

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. On Jan. 25, 2007, the court issued its decision and remanded virtually every aspect of the rule to the EPA for reconsideration. The EPA announced on March 20, 2007, it will suspend the deadlines and refer any implementation to each state s best professional judgment until the

EPA is able to fully respond to the court-ordered remands. 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.

PSCo Notice of Violation On July 1, 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.

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.

Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al**.** In February 2007, a complaint was filed alleging that NSP-Wisconsin, Xcel Energy and e prime, among others, engaged in fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. The plaintiffs seek a declaration that contracts for natural gas entered into between Jan. 1, 2000 and Oct. 31, 2002 are void, that they are entitled to repayment for amounts paid for natural gas during that time period, and that treble damages are appropriate. The case was filed in the Wisconsin State Court (Dane County), and then removed to U.S. District Court for the Western District of Wisconsin. In June 2007, the plaintiffs filed a motion to remand the matter to state court, which was denied and then transferred by the Multi-District Litigation (MDL) panel to Federal District Court Judge Pro in Nevada, who is the judge assigned to western area wholesale natural gas marketing litigation. In July 2007, plaintiffs filed an amended complaint in Federal District Court in Nevada, which includes allegations against NRG, a former Xcel Energy subsidiary.

Heartland Regional Medical Center vs. e prime, Xcel Energy et al. In March 2007, a complaint was filed in the Circuit Court of Buchanan County, Missouri on behalf of a purported class of natural gas purchasers alleging that defendants, including e prime and Xcel Energy, engaged in a conspiracy and falsely reported natural gas trades in an effort to artificially raise natural gas prices. The complaint alleges restraint of trade, price manipulation, and violation of Missouri s antitrust laws. e prime and Xcel Energy deny the allegations and, together with the other defendants, intend to seek dismissal of all claims.

Bender et al. vs. Xcel Energy On July 2, 2004, five former NRG officers filed a lawsuit against Xcel Energy in the U.S. District Court for the District of Minnesota. The lawsuit alleges, among other things, that Xcel Energy violated the ERISA by refusing to make certain deferred compensation payments to the plaintiffs. The complaint also alleges interference with ERISA benefits, breach of contract related to the nonpayment of certain stock options and unjust enrichment. The complaint alleges damages of approximately $6 million. Xcel Energy believes the suit is without merit. On Jan. 19, 2005, Xcel Energy filed a motion for summary judgment. On July 26, 2005, the court issued an order granting Xcel Energy s motion for summary judgment in part with respect to claims for interference with ERISA benefits, breach of contract for nonpayment of stock options and unjust enrichment. The court denied Xcel Energy s motion in part with respect to the allegations of nonpayment of deferred compensation benefits. Plaintiffs and Xcel Energy filed additional cross motions for summary judgment, with oral arguments presented on Feb. 24, 2006.

On May 17, 2006, the court granted Xcel Energy s motion for summary judgment in full and denied the plaintiff s motion for summary judgment in full. Plaintiffs have appealed to the Eighth Circuit Court of Appeals. Oral arguments were presented Jan. 11, 2007 and a decision is pending.

Carbon Dioxide Emissions Lawsuit On July 21, 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO_2) emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. CO_2 is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or natural gas-fired power plants. 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 four other utility companies filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the judge granted the defendants motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the Second Circuit Court of Appeals. On June 21, 2007 the Second Circuit Court of Appeals issued an order requesting the parties to file a letter brief informing the Second Circuit Court of Appeals of their views about the impact of the United States Supreme Court s decision in Massachusetts v. EPA, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in Massachusetts v. EPA, the United States Supreme

Court held that CO2 emissions are a pollutant subject to regulation by the EPA under the Clean Air Act. In response to the request of the Second Circuit Court of Appeals, the defendant utilities filed a letter brief on July 6, 2007, stating the position that the United States Supreme Court s decision supports the arguments raised by them on appeal. It is unknown when the Second Circuit Court of Appeals will rule on the appeal.

Texas-Ohio Energy, Inc. vs. Centerpoint Energy et al. On Nov. 19, 2003, a class action complaint filed in the U.S. District Court for the Eastern District of California by Texas-Ohio Energy, Inc. was served on Xcel Energy naming e prime as a defendant. The lawsuit, filed on behalf of a purported class of large wholesale natural gas purchasers, alleges that e prime falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California. The case has been conditionally transferred by the MDL panel to U.S. District Judge Pro, in Nevada, who is the judge assigned to western area wholesale natural gas marketing litigation. In an order entered April 8, 2005, Judge Pro granted the defendants motion to dismiss based on the filed rate doctrine. On May 9, 2005, plaintiffs filed an appeal of this decision to the 9th Circuit Court of Appeals and oral arguments on the appeal were heard on Feb. 13, 2007.

Fairhaven Power Company vs. Encana Corporation et al. On Sept. 14, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Fairhaven Power Co. and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs. Centerpoint Energy *et al*. and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on Dec. 19, 2005. The plaintiffs subsequently appealed and the appeal is pending.

Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. On Nov. 29, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Utility Savings and Refund Services LLP and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs. Centerpoint Energy *et al.* and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on Dec. 19, 2005. Plaintiffs subsequently appealed and the appeal is pending.

Abelman Art Glass vs. Ercana Corporation et al. On Dec. 13, 2004, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Abelman Art Glass and subsequently served on Xcel Energy. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that Xcel Energy falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California and engaged in a conspiracy with other sellers of natural gas to inflate prices. This case has been consolidated with Texas-Ohio Energy, Inc. vs. Centerpoint Energy et al and assigned to U.S. District Judge Pro. Defendants filed a motion to dismiss, which was granted on Dec. 19, 2005. Plaintiffs subsequently appealed to the 9^{th} Circuit Court of Appeals and oral arguments on the appeal were heard on Feb. 13, 2007.

Sinclair Oil Corporation vs. e prime, inc. and Xcel Energy Inc. On July 18, 2005, Sinclair Oil Corporation filed a lawsuit against Xcel Energy and its former subsidiary e prime, inc. in the U.S. District Court for the Northern District of Oklahoma alleging liability and damages for purported misreporting of price information for natural gas to trade publications in an effort to artificially increase natural gas prices. The complaint also alleges that e prime and Xcel Energy engaged in a conspiracy with other natural gas sellers to inflate prices through alleged false reporting of natural gas prices. In response, e prime and Xcel Energy filed a motion with the MDL panel to have the matter transferred to U.S. District Judge Pro, who is the judge assigned to western area wholesale natural gas marketing litigation and filed a second motion to dismiss the lawsuit. In response to this motion, this matter was conditionally transferred to U.S. District Court Judge Pro. Judge Pro granted the motion to dismiss, and Sinclair appealed to the Ninth Circuit Court of Appeals. Sinclair s appeal has been stayed pending the Ninth Circuit s disposition of the Abelman Art Glass and Texas-Ohio appeals.

Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al. On June 21, 2005, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Ever-Bloom, Inc. The lawsuit names as defendants, among others, Xcel Energy and e prime. The lawsuit, filed on behalf of a purported class of natural gas purchasers, alleges that defendants falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California, purportedly in violation of the Sherman Act. This matter has been stayed pending the outcome of cases on appeal to the Ninth Circuit Court of Appeals.

Learjet, Inc. vs. e prime and Xcel Energy et al. On Nov. 4, 2005, a purported class action complaint was filed in State Court for Wyandotte County of Kansas on behalf of all natural gas producers in Kansas. The lawsuit alleges that e prime, Xcel Energy and other named defendants conspired to raise the market price of natural gas in Kansas by, among other things, inaccurately reporting price and volume information to the market trade publications. On Dec. 7, 2005, the state court granted the defendants motion to remove this matter to the U.S. District Court in Kansas. Plaintiffs have filed a motion for remand, which was denied on Aug. 3, 2006. Plaintiffs in this matter and in the J.P. Morgan Trust case, discussed below, have moved the judicial panel on MDL for a separate MDL docket to be set up in Kansas Federal Court. Xcel Energy s motion to dismiss the complaint is pending.

J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al. On Oct. 17, 2005, J.P. Morgan Trust Company, in its capacity as the liquidating trustee for Farmland Industries Liquidating Trust, filed an amended complaint in Kansas State Court adding defendants, including Xcel Energy and e prime, to a previously filed complaint alleging that the defendants inaccurately reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices. The lawsuit was removed to the U.S. District Court in Kansas and subsequently transferred to U.S. District Court Judge Pro in Nevada pursuant to an order from the MDL panel. A motion to remand to state court filed by plaintiffs has been denied. A motion to dismiss plaintiff s case was granted in December 2006. Plaintiff subsequently filed a motion to amend the judgment and defendants filed an opposition to that motion in February 2007.

Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al. In May, 2006, Breckenridge Brewery, a Colorado corporation, filed a complaint in Colorado State District Court for the City and County of Denver alleging that the defendants, including e prime and Xcel Energy, unlawfully prevented full and free competition in the trading and sale of natural gas, or controlled the market price of natural gas, and engaged in a conspiracy in constraint of trade. Notice of removal to federal court on behalf of Xcel Energy Inc. and e prime, inc. was filed in June 2006. On July 6, 2006, the Colorado State District Court granted an enlargement of time within which to file a pleading in response to the complaint. Defendants motion to dismiss, filed in January 2007, is pending.

Plaintiffs filed a motion to remand the matter to state court, which was denied in October 2006, and the matter has been transferred to U.S. District Court Judge Pro, in Nevada.

Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. On Oct. 24, 2006, the Missouri Public Utilities Commission filed a complaint in State Court for Jackson County of Missouri alleging that e prime, Xcel Energy and 21 other defendants falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices. The complaint further alleges that such conduct constitutes a violation of the Missouri Antitrust Law, fraud and unjust enrichment. This matter has been removed to U.S. District Court, and plaintiffs have indicated they intend to file a motion to remand to state court. Xcel Energy and e prime deny plaintiffs allegations and intend to vigorously defend themselves in this action.

Payne et al. vs. PSCo et al. In late October 2003, there was a wildfire in Boulder County, Colorado. There was no loss of life, but there was property damage associated with this fire. On Oct. 28, 2005, an action against PSCo relating to this fire was filed in Boulder County District Court. There are 22 plaintiffs, including individuals, the City of Jamestown and two companies, and three co-defendants, including PSCo. Plaintiffs asserted that a tree falling into PSCo distribution lines may have caused the fire. The matter was ultimately settled in March 2007 and the settlement did not have a material effect on Xcel Energy s financial results.

Comanche 3 Permit Litigation On Aug. 4, 2005, Citizens for Clean Air and Water in Pueblo and Southern Colorado and Clean Energy Action filed a complaint against the Colorado Air Pollution Control Division 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. On June 20, 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 have appealed this decision. On Nov. 22, 2006, plaintiffs filed their opening briefs. PSCo s response was filed Dec. 22, 2006. The Colorado Court of Appeals is expected to rule on the appeal in 2007.

Fru-Con Construction Corporation vs. Utility Engineering (UE) et al. On March 28, 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court for 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. UE denies this claim and intends to vigorously defend itself. Because this lawsuit was commenced prior to the April 8, 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. On June 1, 2005, UE filed a motion to dismiss Fru-Con s complaint. A hearing concerning this motion was held on July 18, 2005, with the court taking the matter under advisement. On Aug. 4, 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.

Metropolitan Airports Commission vs. Northern States Power Company On Dec. 30, 2004, the Metropolitan Airports Commission (MAC) filed a complaint in Minnesota State District Court in Hennepin County asserting that NSP-Minnesota is required to relocate facilities on MAC property at the expense of NSP-Minnesota. MAC claims that approximately $7.1 million charged by NSP-Minnesota over the past five years for relocation costs should be repaid. Both parties asserted cross motions for partial summary judgment on a separate and less significant claim concerning legal obligations associated with rent payments allegedly due and owing by NSP-Minnesota to MAC for the use of its property for a substation that serves MAC. A hearing regarding these cross motions was held in January 2006. In February 2006, the court granted MAC s motion on this issue, finding that there was a valid lease and that the past course of action between the parties required NSP-Minnesota to continue making rent payments. NSP-Minnesota had made rent payments for 45 years. Depositions of key witnesses took place in February, March and April of 2006. The parties entered into settlement negotiations in May 2006, and in August 2006 reached an oral settlement of the dispute. The parties are negotiating the final form of the settlement documents and it is expected that the action will be formally dismissed in the near future.

Siewert vs. Xcel Energy Plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action 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 expert report on the economic damage to their dairy farm states that the total present value of plaintiffs loss is $6.8 million. NSP-Minnesota denies all allegations, has made motions to exclude the testimony of Plaintiffs experts, and both sides have made motions for summary judgment. A hearing on the various motions is currently scheduled for Aug. 28, 2007. Trial is scheduled to commence in January 2008

Hoffman vs. Northern States Power Company On March 15, 2006, a purported class action complaint was filed in Minnesota State District Court in Hennepin County, 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. NSP-Minnesota filed a motion for dismissal on the pleadings, which was heard on Aug. 16, 2006. In November 2006, the court issued an order denying NSP-Minnesota s motion. On Nov. 28, 2006, pursuant to a motion by NSP-Minnesota, the court certified the issues raised in NSP-Minnesota s original motion as important and doubtful. This certification permits NSP-Minnesota to file an appeal, and it has done so. Briefs have been filed, but a date for oral arguments has not yet been set.

Comer vs. Xcel Energy Inc. et al. On April 25, 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court for the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants CO2 emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. On July 19, 2006, Xcel Energy filed a motion to dismiss the lawsuit in its entirety. Oral arguments related to some of the defenses raised by the defendants, including Xcel Energy, have been set for Aug. 30, 2007.

Qwest vs. Xcel Energy Inc. - On June 24, 2004, an employee of PSCo was injured when a pole owned by Qwest malfunctioned. The employee is seeking damages of approximately $7 million. On Sept. 6, 2005, an action against Qwest relating to the incident was filed in Denver District Court by the employee. On April 18, 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 has asserted that PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. PSCo filed a counterclaim on May 15, 2006, 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. On May 14, 2007 this matter went to trial. The trial concluded on May 22, 2007 with a jury verdict that found Qwest solely liable for the accident and damages. Qwest has filed post trial motions and has indicated that, if the motions are unsuccessful, it will appeal the verdict.

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, on Oct. 28, 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. On Nov. 12, 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. Although the Wisconsin action has not been dismissed, the January 2007 trial date was adjourned and has not been rescheduled.

NSP-Wisconsin has entered into confidential settlements with St. Paul Mercury Insurance Company, St. Paul Fire and Marine Insurance Company and the Phoenix Insurance Company (St. Paul Companies), Associated Electric & Gas Insurance Services Limited, Fireman s Fund Insurance Company, INSCO, Ltd. (on its own behalf and on behalf of the insurance companies subscribing per Britamco, Ltd.), Allstate Insurance Company, Admiral Insurance Company; certain underwriters at Lloyd s, London and certain London Market Insurance Companies (London Market Insurers), and Compagnie Europeene D Assurances Industrielles S.A. These insurers have been dismissed from the Minnesota and Wisconsin actions.

NSP-Wisconsin has reached settlements in principle with General Reinsurance Corporation; First State Insurance Company; Twin City Fire Insurance Company; Continental Insurance Company, as successor in interest by merger to Fidelity and Casualty Company of New York; Columbia Casualty Company; Continental Casualty Company; and Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company.

On Oct. 6, 2006, the trial court issued a memorandum and order on various summary judgment motions. The court ruled that Minnesota law on allocation applies and ordered dismissal, without prejudice, of 15 carriers whose coverage would not be triggered under such an allocation method. On July 6, 2007, the court issued a decision reaffirming its Oct. 6, 2006 order adopting Minnesota law on allocation. In addition, based upon the trial court s interpretation of the Minnesota Supreme Court s allocation decision in Wooddale Builders Inc. v. Maryland Casualty Company, 722 N.W.2d 283 (Minn. 2006), the trial court granted summary judgment, without prejudice, to approximately 16 insurers whose coverage would not be triggered under Minnesota allocation principles. Judgment was entered July 9, 2007. On July 16, 2007, the court issued a memorandum and order amending its July 6, 2007 decision to correct mathematical and other errors. Trial commenced July 16, 2007 against Century Indemnity Company, as successor to California Union Insurance Company (Century Indemnity) and Westchester Fire Insurance Company as successor to United States Fire Insurance Company (Westchester), the two remaining insurers in the case. On July 17, 2007, NSP-Wisconsin reached a settlement in principle with Century Indemnity; Westchester; Insurance Company of North America (INA); Pacific Employers Insurance Company; and Central National Insurance Company, and the trial was terminated. NSP-Wisconsin has until Sept.17, 2007 to commence an appeal of trial court orders entered in the case.

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 operate as a credit to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy s financial results.

Other Contingencies

Tax Matters See Note 4 to the consolidated financial statements for discussion of exposures regarding the tax deductibility of corporate-owned life insurance loan interest; and

Guarantees See Note 7 to the consolidated financial statements for discussion of exposures under various guarantees.

7. Short-Term Borrowings and Other Financing Instruments

Short-Term Borrowings

At June 30, 2007, Xcel Energy and its subsidiaries had approximately $620.2 million of short-term debt outstanding at a weighted average interest rate of 5.43 percent.

Guarantees

Xcel Energy provides various guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On June 30, 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 June 30, 2007, was approximately $36.6 million. 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.

8. Long-Term Borrowings and Other Financing Instruments

Long-Term Borrowings

During the second quarter of 2007, approximately $126 million of the Xcel convertible notes due Nov. 21, 2007, were converted to common stock.

On June 26, 2007, NSP-Minnesota issued $350 million of 6.20 percent first mortgage bonds, series due July 1, 2037. 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.

On June 29, 2007, NSP-Minnesota announced that it will redeem all of its outstanding 8.00 percent Notes, Series due 2042. The redemption will take place on Aug. 1, 2007. NSP-Minnesota will redeem the notes at a redemption price equal to 100 percent of the principal amount of the notes ($25.00), plus accrued and unpaid interest on the notes, if any, to the redemption date.

Debt Exchange

On March 30, 2007, Xcel Energy settled an exchange offer for up to $350 million aggregate principal amount of its 7 percent Senior Notes, Series due 2010 (the Old Notes). Xcel Energy accepted approximately $241.4 million aggregate principal amount of its Old Notes in exchange for approximately $254.0 million aggregate principal amount of a new series of 5.613 percent senior notes due April 1, 2017 (the New Notes). The $12.6 million non-cash increase in the aggregate principal amount was a result of financing the premium associated with the exchange. In addition, Xcel Energy paid the following amounts in cash: (i) approximately $4.8 million to certain investors as an early participation payment for Old Notes validly tendered prior to 5:00 p.m., New York City time, on March 13, 2007 and accepted for exchange; (ii) approximately $57,000 in cash in lieu of New Notes; and (iii) accrued and unpaid interest to, but not including, the settlement date with respect to the Old Notes accepted for exchange.

The New Notes were issued only to holders of Old Notes that certified certain matters to Xcel Energy, including their status as either qualified institutional buyers, as that term is defined in Rule 144A under the Securities Act of 1933, or persons other than U.S. persons, as that term is defined in Rule 902 under the Securities Act of 1933. The New Notes were issued with a registration rights agreement.

In accordance with the Emerging Issues Task Force Issue No. 96-19 (EITF 96-19), Debtor s Accounting for a Modification or Exchange of Debt Instruments, this transaction was accounted for as an exchange. As such, the fees paid to the bondholders have been associated with the replacement debt instruments and, along with the existing unamortized discount, will be amortized as an adjustment of interest expense over the remaining term of the replacement debt instruments. Also, as required by EITF 96-19, the fees paid to third parties were expensed as incurred and $1.7 million was included in interest charges and other financing costs in the Consolidated Statements of Income.

On June 19, 2007, Xcel Energy filed a registration statement with the SEC to exchange the New Notes for exchange notes, which have terms identical in all material respects to the New Notes, except that the exchange notes do not contain transfer restrictions nor are they subject to registration rights.

9. Derivative Valuation and Financial Impacts

Xcel Energy and its subsidiaries use a number of different derivative instruments in connection with their utility operations, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. These derivative instruments are utilized in connection with various commodity prices, certain energy related products, including emission allowances and renewable energy credits, and interest rates. All derivative instruments not qualifying for the normal purchases and normal sales exception, as defined by SFAS 133- Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS 133), are recorded at fair value. The presentation of these derivative instruments is dependent on the designation of a qualifying hedging relationship. The adjustment to fair value of derivative instruments not designated in a qualifying hedging relationship is reflected in current earnings or as a regulatory balance.

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheets as separate line items identified as Derivative Instruments Valuation in both current and noncurrent assets and liabilities. The fair value of all interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

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 in which Xcel Energy and its subsidiaries are currently engaged are discussed below.

Cash Flow Hedges

Xcel Energy and its subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices and interest rates.

As of June 30, 2007, Xcel Energy and its utility subsidiaries had various commodity-related contracts designated as cash flow hedges extending through December 2009. The fair value of these cash flow hedges is 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.

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, and the change in the fair value of these instruments is recorded as a component of Other Comprehensive Income.

As of June 30, 2007, Xcel Energy had net gains of approximately $2.3 million in Accumulated Other Comprehensive Income related to interest rate cash flow hedge contracts that are expected to be recognized in earnings during the next 12 months.

Gains or losses on hedging transactions for the sales of energy or energy-related products are recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs, hedging transactions for gas purchased for resale are recorded as a component of gas costs and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. There was an immaterial amount of ineffectiveness in the second quarter of 2007.

The impact of qualifying cash flow hedges on Xcel Energy s Accumulated Other Comprehensive Income, included in the Consolidated Statements of Stockholders Equity and Comprehensive Income, is detailed in the following table:

(Millions of Dollars)	Three months ended June 30, 2007		Three months ended June 30, 2006	
Accumulated other comprehensive income related to cash flow hedges at April 1	$	1.4	$	9.2
After-tax net unrealized gains related to derivatives accounted for as hedges		7.1		12.1
After-tax net realized gains on derivative transactions reclassified into earnings		(0.2)		(1.8)
Accumulated other comprehensive income related to cash flow hedges at June 30	$	8.3	$	19.5

(Millions of Dollars)	Six months ended June 30, 2007		Six months ended June 30, 2006	
Accumulated other comprehensive income (loss) related to cash flow hedges at Jan. 1	$	2.2	$	(8.8)
After-tax net unrealized gains related to derivatives accounted for as hedges		6.6		28.8
After-tax net realized gains on derivative transactions reclassified into earnings		(0.5)		(0.5)
Accumulated other comprehensive income related to cash flow hedges at June 30	$	8.3	$	19.5

Fair Value Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge is offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the gains or losses of the derivative instrument to offset, in the same period, the gains and losses of the hedged item.

Derivatives Not Qualifying for Hedge Accounting

Xcel Energy and its subsidiaries enter into certain commodity-based derivative transactions, not included in trading operations, which do not qualify for hedge accounting treatment. These derivative instruments are accounted for on a mark-to-market basis in accordance with SFAS 133 and are recorded on a net basis within Operating Revenues on the Consolidated Statements of Income.

Normal Purchases or Normal Sales Contracts

Xcel Energy s utility subsidiaries enter into contracts for the purchase and sale of various commodities for use in their business operations. SFAS 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that meet the definition of a derivative may be exempted from SFAS 133 as normal purchases or normal sales.

Xcel Energy evaluates all of its contracts when such contracts are entered to determine if they are derivatives and, if so, if they qualify to meet the normal designation requirements under SFAS 133. None of the contracts entered into within the commodity trading operations qualify for a normal designation.

10. Detail of Interest and Other Income (Expense), Net

Interest and other income, net of nonoperating expenses, for the three and six months ended June 30 consisted of the following:

(Thousands of dollars)	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Interest income	$ 4,483	$ 5,596	$ 9,079	$ 9,653
Equity income in unconsolidated affiliates	1,107	1,092	2,185	2,278
Other nonoperating income	611	2,588	1,231	4,094
Minority interest income	113	253	247	303
Other nonoperating expense	(1,941)	(2,878)	(3,687)	(5,935)
Total interest and other income, net	$ 4,373	$ 6,651	$ 9,055	$ 10,393

11. Common Stock and Equivalents

Xcel Energy has common stock equivalents consisting of convertible senior notes, 401(k) equity awards and stock options. For the three and six months ended June 30, 2007 and 2006, Xcel Energy had approximately 10.6 million and 12.9 million options outstanding, respectively, that were antidilutive and, therefore, excluded from the dilutive earnings per share calculation.

The dilutive impacts of common stock equivalents affected earnings per share as follows for the three and six months ending June 30, 2007 and 2006:

	Three months ended June 30, 2007			Three months ended June 30, 2006		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 124,103			$ 98,089		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Income from continuing operations	123,043	412,710	$ 0.30	97,029	405,434	$ 0.24
Effect of dilutive securities:						
$230 million convertible debt	2,226	15,113		3,044	18,654	
$57.5 million convertible debt	783	4,663		779	4,663	
401(k) equity awards		275			330	
Stock options		100			18	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 126,052	432,861	$ 0.29	$ 100,852	429,099	$ 0.24

	Six months ended June 30, 2007			Six months ended June 30, 2006		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 238,283			$ 241,208		
Less: Dividend requirements on preferred stock	(2,120)			(2,120)		
Basic earnings per share:						
Income from continuing operations	236,163	410,370	$ 0.58	239,088	404,783	$ 0.59

Effect of dilutive securities:						
$230 million convertible debt	5,270	16,880		6,002	18,654	
$57.5 million convertible debt	1,545	4,663		1,501	4,663	
401(k) equity awards		443			231	
Stock options		115			18	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 242,978	432,471	$ 0.56	$ 246,591	428,349	$ 0.58

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three months ended June 30,			
	2007	2006	2007	2006
(Thousands of dollars)	**Pension Benefits**		**Postretirement Health Care Benefits**	
Service cost	$ 14,555	$ 14,380	$ 1,205	$ 1,479
Interest cost	43,028	38,197	11,635	13,287
Expected return on plan assets	(66,525)	(67,551)	(7,582)	(7,110)
Amortization of transition obligation			3,677	3,577
Amortization of prior service cost (credit)	6,487	7,421	(545)	(545)
Amortization of net loss	4,555	4,165	2,106	5,875
Net periodic benefit cost (credit)	2,100	(3,388)	10,496	16,563
Credits not recognized due to the effects of regulation	2,894	3,893		
Additional cost recognized due to the effects of regulation			973	973
Net benefit cost recognized for financial reporting	$ 4,994	$ 505	$ 11,469	$ 17,536

	Six months ended June 30,			
	2007	2006	2007	2006
(Thousands of dollars)	**Pension Benefits**		**Postretirement Health Care Benefits**	
Service cost	$ 31,040	$ 30,814	$ 2,906	$ 3,316
Interest cost	82,626	77,706	25,238	26,470
Expected return on plan assets	(132,416)	(134,032)	(15,200)	(13,378)
Amortization of transition obligation			7,288	7,222
Amortization of prior service cost (credit)	12,974	14,848	(1,090)	(1,090)
Amortization of net loss	8,422	8,676	7,100	12,398
Net periodic benefit cost (credit)	2,646	(1,988)	26,242	34,938
Credits not recognized due to the effects of regulation	5,574	6,318		
Additional cost recognized due to the effects of regulation			1,946	1,946
Net benefit cost recognized for financial reporting	$ 8,220	$ 4,330	$ 28,188	$ 36,884

13. Segment Information

Xcel Energy has the following reportable segments: Regulated Electric Utility, Regulated Natural Gas Utility and All Other. Commodity trading operations performed by regulated operating companies are not a reportable segment. Commodity trading results are included in the Regulated Electric Utility segment.

(Thousands of Dollars)

	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Three months ended June 30, 2007					
Operating revenues from external customers	$ 1,919,695	$ 330,868	$ 16,729	$	$ 2,267,292
Intersegment revenues	186	5,780		(5,966)	
Total revenues	$ 1,919,881	$ 336,648	$ 16,729	$ (5,966)	$ 2,267,292
Income (loss) from continuing operations	$ 123,829	$ 8,911	$ 2,812	$ (11,449)	$ 124,103
Three months ended June 30, 2006					
Operating revenues from external customers	$ 1,786,571	$ 270,990	$ 16,312	$	$ 2,073,873
Intersegment revenues	225	1,228		(1,453)	
Total revenues	$ 1,786,796	$ 272,218	$ 16,312	$ (1,453)	$ 2,073,873
Income (loss) from continuing operations	$ 93,783	$ 2,955	$ 20,936	$ (19,585)	$ 98,089

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Six months ended June 30, 2007					
Operating revenues from external customers	$ 3,735,498	$ 1,258,290	$ 37,166	$	$ 5,030,954
Intersegment revenues	515	10,168		(10,683)	
Total revenues	$ 3,736,013	$ 1,268,458	$ 37,166	$ (10,683)	$ 5,030,954
Income (loss) from continuing operations	$ 195,964	$ 65,832	$ 9,259	$ (32,772)	$ 238,283
Six months ended June 30, 2006					
Operating revenues from external customers	$ 3,632,443	$ 1,289,130	$ 40,404	$	$ 4,961,977
Intersegment revenues	387	3,767		(4,154)	
Total revenues	$ 3,632,830	$ 1,292,897	$ 40,404	$ (4,154)	$ 4,961,977
Income (loss) from continuing operations	$ 203,734	$ 48,174	$ 22,177	$ (32,877)	$ 241,208

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. 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; 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, including the approval of the COLI settlement discussed below; 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, 2006 and Exhibit 99.01 to this report on Form 10-Q for the quarter ended June 30, 2007.

RESULTS OF OPERATIONS

Summary of Financial Results

The following table summarizes the earnings contributions of Xcel Energy s business segments on the basis of generally accepted accounting principles (GAAP). Continuing operations consist of the following:

regulated utility subsidiaries, operating in the electric and natural gas segments; and

several nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of Cheyenne, Seren Innovations Inc., NRG Energy, Inc., e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all sold in 2006 or earlier. In addition, discontinued operations include PSRI due to a settlement in principle and management s decision to surrender all COLI policies when the offer has been accepted in writing by the government.

See Note 3 to the consolidated financial statements for a further discussion of discontinued operations.

Contribution to Earnings (Millions of dollars)	Three months ended June 30, 2007	2006	Six months ended June 30, 2007	2006
GAAP income (loss) by segment				
Regulated electric utility segment income continuing operations	$ 123.8	$ 93.7	$ 196.0	$ 203.7
Regulated natural gas utility segment income continuing operations	8.9	3.0	65.8	48.2
Other utility results (a)	7.3	5.2	17.5	12.1
Utility segment income continuing operations	140.0	101.9	279.3	264.0
Holding company and other results	(15.9)	(3.8)	(41.0)	(22.8)
Income continuing operations	124.1	98.1	238.3	241.2
Regulated utility income discontinued operations				1.2
Other nonregulated income discontinued operations	(48.1)	0.2	(42.6)	7.2
Income discontinued operations	(48.1)	0.2	(42.6)	8.4
Total GAAP income	$ 76.0	$ 98.3	$ 195.7	$ 249.6

	Three months ended June 30, 2007	2006	Six months ended June 30, 2007	2006
GAAP earnings per share contribution by segment				
Regulated electric utility segment continuing operations	$ 0.29	$ 0.22	$ 0.45	$ 0.48
Regulated natural gas utility segment continuing operations	0.02		0.15	0.11
Other utility results (a)	0.01	0.02	0.05	0.03
Utility segment earnings per share continuing operations	0.32	0.24	0.65	0.62
Holding company and other results	(0.03)		(0.09)	(0.04)
Earnings per share continuing operations	0.29	0.24	0.56	0.58
Regulated utility earnings discontinued operations				
Other nonregulated earnings discontinued operations	(0.11)		(0.10)	0.02
Earnings per share discontinued operations	(0.11)		(0.10)	0.02
Total GAAP earnings per share - diluted	$ 0.18	$ 0.24	$ 0.46	$ 0.60

(a) Not a reportable segment. Included in All Other segment results in Note 13 to the consolidated financial statements. Other utility results, included in the earnings contribution table above, include certain subsidiaries of the utility operating companies that conduct non-utility activities.

The following table summarizes significant components contributing to the changes in the three months and six months ended June 30, 2007 earnings per share compared with the same period in 2006, which are discussed in more detail later.

Increase (decrease)	Three months ended June 30, 2007 vs. 2006	Six months ended June 30, 2007 vs. 2006
2006 Earnings per share	**$ 0.24**	**$ 0.60**
Components of change 2007 vs. 2006		

Higher base electric utility margins		0.05		0.05
Higher short-term wholesale and commodity trading margins		0.02		
Higher natural gas margins		0.01		0.04
Lower (higher) operating and maintenance expense		0.01		(0.03)
Higher depreciation and amortization		(0.02)		(0.03)
Higher effective tax rate and other		(0.02)		(0.05)
Net change in earnings per share continuing operations		**0.05**		**(0.02)**
Changes in Earnings Per Share Discontinued Operations		(0.11)		(0.12)
2007 Earnings per share	**$**	**0.18**	**$**	**0.46**

Utility Segment Results

Utility earnings from continuing operations for the second quarter of 2007 were higher than last year, due to several factors including higher electric margin, reflecting the positive impact of the January 2007 Colorado rate increase, incremental margin from the MERP rider and improved short term wholesale and trading margins. Additionally, lower operating and maintenance expenses, resulting from lower second quarter 2007 nuclear plant outage costs associated with the timing of plant refueling, as well as lower employee benefit costs also contributed to the higher current period earnings.

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 June 30,			Six months ended June 30,		
	2007 vs. Normal	**2006 vs. Normal**	**2007 vs. 2006**	**2007 vs. Normal**	**2006 vs. Normal**	**2007 vs. 2006**
Retail electric	$ 0.01	$ 0.03	$ (0.02)	$ 0.01	$ 0.01	$
Firm natural gas		(0.01)	0.01		(0.02)	0.02
Total	$ 0.01	$ 0.02	$ (0.01)	$ 0.01	$ (0.01)	$ 0.02

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

Discontinued - Utility Segments Cheyenne, which was sold in 2005, had income tax adjustments that impacted 2006 results.

Discontinued 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. In addition, discontinued operations include PSRI due to a settlement in principle and management s decision to surrender all COLI policies when the offer has been accepted in writing by the government.

Income Statement Analysis Second Quarter 2007 vs. Second Quarter 2006

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 costs 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 June 30, 2007				
Electric utility revenues (excluding commodity trading)	$ 1,864	$ 57	$	$ 1,921
Electric fuel and purchased power	(980)	(52)		(1,032)
Commodity trading revenues			76	76
Commodity trading costs			(77)	(77)
Gross margin before operating expenses	$ 884	$ 5	$ (1)	$ 888
Margin as a percentage of revenues	47.4%	8.8%	(1.3)%	44.5%
Three months ended June 30, 2006				
Electric utility revenues (excluding commodity trading)	$ 1,761	$ 34	$	$ 1,795
Electric fuel and purchased power	(913)	(38)		(951)
Commodity trading revenues			119	119
Commodity trading costs			(127)	(127)
Gross margin before operating expenses	$ 848	$ (4)	$ (8)	$ 836
Margin as a percentage of revenues	48.2%	(11.8)%	(6.7)%	43.7%

Short-term wholesale and commodity trading margins increased $16 million during the second quarter of 2007. The improved margins are attributable, in part, to the second quarter 2006 recognition of a $6 million change associated with the estimated impact of a Federal Energy Regulatory Commission order regarding the allocation of Midwest Independent Transmission System Operator charges to certain trading activities and an adjustment to reflect a regulatory margin sharing mechanism in Minnesota.

The following summarizes the components of the changes in base electric utility revenues and base electric utility margin for the three months ended June 30:

Base Electric Utility Revenue

(Millions of dollars)	2007 vs. 2006
Fuel and purchased power cost recovery	$ 56
PSCo electric retail rate increase	26
Sales growth (excluding weather impact)	16
Transmission revenue	16
MERP rider	7
Estimated impact of weather	(7)
Other	(11)
Total increase in base electric utility revenues	$ 103

Base Electric Utility Margin

(Millions of dollars)		**2007 vs. 2006**
PSCo electric retail rate increase	$	26
Sales growth (excluding weather impact)		16
MERP rider		7
SPS 2006 fuel recovery		7
NSP-Wisconsin fuel and purchased power cost recovery		(9)
Estimated impact of weather		(7)
Transmission fee classification change		(6)
Other, including sales mix, other fuel recovery and purchased capacity costs		2
Total increase in base electric utility margin	$	36

Natural Gas Utility Margins

The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of 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 June 30, 2007**	**2006**
Natural gas utility revenue	$ 331	$ 271
Cost of natural gas sold and transported	(220)	(169)
Natural gas utility margin	$ 111	$ 102

The following summarizes the components of the changes in natural gas revenue and margin for the three months ended June 30:

Natural Gas Revenue

(Millions of dollars)	**2007 vs. 2006**
Purchased gas adjustment clause recovery	$ 47
Estimated impact of weather	4
Base rate changes Minnesota (interim), North Dakota	4
Sales growth (excluding weather impact)	2
Other	3
Total increase in natural gas revenues	$ 60

Natural Gas Margin

(Millions of dollars)	**2007 vs. 2006**
Base rate changes Minnesota (interim), North Dakota	$ 4
Estimated impact of weather	3
Sales growth (excluding weather impact)	1
Other	1
Total increase in natural gas margin	$ 9

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses Utility Other operating and maintenance expenses for the second quarter of 2007 decreased by approximately $7 million, or 1.6 percent, compared with the same period in 2006. For more information see the following table:

(Millions of Dollars)	Three months ended June 30, 2007 vs. 2006
Lower employee benefit costs	$ (12)
Lower nuclear plant outage costs	(12)
Transmission fees classification change	(6)
Higher combustion/hydro plant costs	7
Higher labor costs	5
Higher nuclear plant operation costs	3
Higher material costs	3
Higher uncollectible receivable costs	3
Higher donations	3
Other	(1)
Total decrease in other operating and maintenance expense-utility	$ (7)

Lower performance based incentive plan expense, as well as improved retired employee health care experience, were the primary factors contributing to the lower employee benefit costs. Lower nuclear plant outage costs are primarily attributable to the timing of scheduled plant refuelings.

Depreciation and Amortization Depreciation and amortization expense increased by approximately $11 million, or 5.4 percent, for the second quarter of 2007, compared with the second quarter of 2006. The increase was primarily due to increased property, plant and equipment expenditures for planned system expansion.

Allowance for funds used during construction, equity and debt (AFDC) AFDC increased in total by approximately $5 million, or 40.7 percent, for second quarter 2007 when compared with the same period in 2006. The increase was due primarily to large capital projects, including MERP and Comanche 3, with long construction periods. The increase was partially offset by the current recovery from customers of the financing costs related to MERP and Comanche 3 through a rate rider or through base rates, respectively, resulting in a lower recognition of AFDC.

Income taxes Income taxes for continuing operations increased by $35 million for the second quarter of 2007, compared with 2006. The effective tax rate for continuing operations was 33.4 percent for the second quarter of 2007, compared with 21.7 percent for the same period in 2006. The lower effective tax rate for second quarter 2006 was primarily due to the recognition of a tax benefit relating to capital loss carry forwards in 2006. Excluding these benefits, the effective tax rate for second quarter 2006 would have been 35.0 percent.

Income Statement Analysis First Six Months of 2007 vs. First Six Months of 2006

Electric Utility, Short-term Wholesale and Commodity Trading Margins

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

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Six months ended June 30, 2007				
Electric utility revenues (excluding commodity trading)	$ 3,616	$ 115	$	$ 3,731
Electric fuel and purchased power	(1,905)	(106)		(2,011)
Commodity trading revenues			153	153
Commodity trading costs			(149)	(149)
Gross margin before operating expenses	$ 1,711	$ 9	$ 4	$ 1,724
Margin as a percentage of revenues	47.3%	7.8%	2.6%	44.4%
Six months ended June 30, 2006				
Electric utility revenues (excluding commodity trading)	$ 3,555	$ 72	$	$ 3,627
Electric fuel and purchased power	(1,882)	(64)		(1,946)

Commodity trading revenues			335	335
Commodity trading costs			(329)	(329)
Gross margin before operating expenses	$ 1,673	$ 8	$ 6	$ 1,687
Margin as a percentage of revenues	47.1%	11.1%	1.8%	42.6%

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the six months ended June 30:

Base Electric Utility Revenues

(Millions of dollars)	2007 vs. 2006
PSCo electric retail rate increase	$ 54
Sales growth (excluding weather impact)	26
Transmission revenue	23
MERP rider	14
Fuel and purchased power cost recovery	(43)
SPS potential regulatory settlements	(13)
Total increase in base electric utility revenues	$ 61

Base Electric Utility Margin

(Millions of dollars)	2007 vs. 2006
PSCo electric retail rate increase	$ 54
Sales growth (excluding weather impact)	25
MERP rider	14
Estimated impact of weather	3
NSP-Wisconsin fuel and purchased power cost recovery	(19)
SPS potential regulatory settlements	(13)
Transmission fee classification change	(11)
Other, including sales mix, other fuel recovery and purchased capacity costs	(15)
Total increase in base electric utility margin	$ 38

Natural Gas Utility Margins

The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of 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.

	Six Months Ended June 30,	
(Millions of Dollars)	2007	2006
Natural gas utility revenue	$ 1,258	$ 1,289
Cost of natural gas sold and transported	(960)	(1,019)
Natural gas utility margin	$ 298	$ 270

The following summarizes the components of the changes in natural gas revenue and margin for the six months ended June 30:

Natural Gas Revenues

(Millions of dollars)	2007 vs. 2006
Purchased gas adjustment clause recovery	$ (83)
Estimated impact of weather	36
Base rate changes Minnesota (interim), North Dakota	8
Sales growth (excluding weather impact)	3
Transportation	1
Other	4
Total decrease in natural gas revenues	$ (31)

Natural Gas Margin

(Millions of dollars)	**2007 vs. 2006**
Estimated impact of weather	$ 13
Base rate changes Minnesota, North Dakota	8
Sales growth (excluding weather impact)	3
Transportation	1
Other	3
Total increase in natural gas margin	$ 28

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses — Utility Other operating and maintenance expenses for the first six months of 2007 increased $19 million, or 2.2 percent, compared with the same period in 2006. For more information see the following table:

(Millions of Dollars)	Six months ended June 30, 2007 vs. 2006
Higher combustion/hydro plant costs	$ 14
Higher nuclear plant operation costs	10
Higher labor costs	8
Higher donations	5
Higher material costs	3
Higher nuclear plant outage costs	2
Transmission fee classification change	(11)
Lower employee benefit costs	(7)
Other	(5)
Total increase in other operating and maintenance expense-utility	$ 19

Lower performance based incentive plan expense, as well as improved retired employee health care experience, were the primary factors contributing to the lower employee benefit costs.

Depreciation and Amortization Depreciation and amortization expense increased by approximately $22 million, or 5.4 percent, for the first six months of 2007, compared with the same period in 2006. The increase was primarily due to increased property, plant and equipment expenditures for planned system expansion.

Allowance for funds used during construction, equity and debt (AFDC) AFDC increased in total by approximately $10 million, or 42.9 percent, for the first six months of 2007 when compared with the same period in 2006. The increase was due primarily to large capital projects, including MERP and Comanche 3, with long construction periods. The increase was partially offset by the current recovery from customers of the financing costs related to MERP and Comanche 3 through a rate rider or through base rates, respectively, resulting in a lower recognition of AFDC.

Income taxes Income taxes for continuing operations increased by $27 million for the first six months of 2007, compared with 2006. The effective tax rate for continuing operations was 33.4 percent for the first six months of 2007, compared with 27.7 percent for the same period in 2006. The lower effective tax rate for the first six months of 2006 was primarily due to the recognition of a tax benefit relating to capital loss carry forwards in 2006. Excluding these benefits, the effective tax rate for the first six months 2006 would have been 32.9 percent.

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 for the year ended Dec. 31, 2006.

Regulation

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy s utility subsidiaries. State and local agencies have jurisdiction over many of Xcel Energy s utility activities, including regulation of retail rates and environmental matters. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Rules Implementing Energy Policy Act of 2005 (Energy Act) The Energy Act repealed the Public Utility Holding Company Act of 1935 effective Feb. 8, 2006. In addition, the Energy Act required the FERC to conduct several rulemakings to adopt new regulations to implement various aspects of the Energy Act. Since August 2005, the FERC has completed or initiated proceedings to modify its regulations on a number of subjects. In addition to the previous disclosure in Item 1 of Xcel Energy s Form 10-K for the year ended Dec. 31, 2006, the FERC issued final rules making certain North American Electric Reliability Corp. (NERC) reliability standards mandatory and subject to potential financial penalties up to $1 million per day per violation for non-compliance effective June 18, 2007.

While Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement these new rules and regulations as they become effective.

Electric Transmission Rate Regulation The FERC also regulates the rates charged and terms and conditions for electric transmission services. FERC policy encourages utilities to turn over the functional control over their electric transmission assets and the related responsibility for the sale of electric transmission services to a Regional Transmission Organization (RTO). NSP-Minnesota and NSP-Wisconsin are members of the MISO. SPS is a member of the Southwest Power Pool, Inc. (SPP). Each RTO separately files regional transmission tariff rates for approval by the FERC. All members within that RTO are then subjected to those rates. PSCo is currently participating with other utilities in the development of WestConnect, which would provide certain regionalized transmission and wholesale energy market functions but would not be an RTO.

On Feb. 15, 2007, the FERC issued final rules adopting revisions to its 1996 open access transmission rules. Xcel Energy submitted the initial required revisions to its Open Access Transmission Tariff (OATT) on July 13, 2007, as required.

In addition, in January 2007, the FERC issued interim and proposed rules to modify the current FERC rules governing the functional separation of the Xcel Energy electric transmission function from the wholesale sales and marketing function. The proposed rules are pending final FERC action.

While Xcel Energy cannot predict the ultimate impact the new regulations will have on its operations or financial results, Xcel Energy is taking actions that are intended to comply with and implement these new rules and regulations as they become effective.

Centralized Regional Wholesale Markets FERC rules require RTO s to operate centralized regional wholesale energy markets. The FERC required the MISO to begin operation of a Day 2 wholesale energy market on April 1, 2005. MISO uses security constrained regional economic dispatch and congestion management using locational marginal pricing (LMP) and Financial Transmission Rights (FTRs). The Day 2 market is intended to provide more efficient generation dispatch over the 15 state MISO region, including the NSP-Minnesota and NSP-Wisconsin systems. SPP received FERC approval to initiate an Energy Imbalance Service (EIS) market, which will provide a more limited wholesale energy market that will affect the SPS system. The SPP EIS market commenced on Feb. 1, 2007.

On Feb. 15, 2007, the MISO filed for FERC approval to establish a Day 3 centralized regional wholesale ancillary services market (ASM) in 2008. The ASM is intended to provide further efficiencies in generation dispatch by allowing for regional regulation and contingency reserve services through a bid-based market mechanism. In addition, MISO would consolidate the operation of 22 existing North American Electric Reliability Council (NERC) approved balancing authorities (the entity responsible for maintaining reliable operations for a defined geographic region) into a single regional balancing authority. The ASM and balancing authority consolidation are expected to benefit NSP-Minnesota and NSP-Wisconsin integrated operation by reducing the total cost of intermittent generation resources such as wind energy. On June 21, 2007, the FERC issued an order rejecting the ASM. The FERC stated the ASM could still be implemented in 2008.

Market Based Rate Rules On June 21, 2007, the FERC issued a final order amending its regulations governing its market-based rate authorizations to electric utilities such as the Xcel Energy operating companies. The FERC reemphasized its commitment to market-based pricing, but is revising the tests it s using to assess whether a utility has market power and has emphasized that it intends to exercise greater oversight where it has market-based rate authorizations. Each of the Xcel Energy operating companies has been granted market-based rate authority and will be subject to the new rule. Xcel Energy is presently analyzing the new rule.

An aspect of FERC s market-based rate requirements is the requirement to charge mitigated rates in markets where a utility is found to have market power or where a utility cannot establish the absence of market power. PSCo and SPS have been authorized by the FERC to charge market-based rates outside of their control areas, but are generally limited to charging mitigated rates within their control areas. Consistent with the approach followed by many other utilities subject to the FERC s mitigation requirement, PSCo and SPS use cost-based rate caps set out in the Western Systems Power Pool (WSPP) agreement as their applicable mitigated rates, an approach expressly approved by the FERC. However, concurrently with the issuance of the final order, the FERC initiated a proceeding to investigate whether the use of the WSPP rate caps for this purpose is just and reasonable. An outcome of this proceeding may be to lower the mitigated rates that PSCo and SPS may charge in their control areas.

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 to act on Excelsior s petition. The contested case proceeding considered a 603 megawatt (MW) unit in phase I and a second 603 MW unit in phase II of the Mesaba Energy Project.

On April 12, 2007, NSP-Minnesota received the ALJ s findings regarding phase I of the contested case. The findings constitute a recommendation and is not binding upon the MPUC. The following summarize the four enumerated recommendations in the findings:

That Excelsior s petition asking the MPUC to approve, amend, or modify the terms and conditions of the power purchase agreement (PPA) be denied and that the PPA be disapproved.

In the event the MPUC approves the PPA, that it first be amended through negotiations among Excelsior, NSP-Minnesota and the MDOC to address the deficiencies identified in the findings, then returned to the MPUC for final approval.

Excelsior s petition asking the MPUC to determine that the project and its IGCC technology is, or is likely to be, a least-cost resource, thus obligating NSP-Minnesota to use the plant s generation for at least two percent of the energy supplied to NSP-Minnesota s retail customers, be denied.

Excelsior s petition asking the MPUC to determine that at least 13 percent of the energy supplied to NSP-Minnesota s retail customers should come from the Units I and II of the Mesaba Energy Project by 2013 be considered in phase 2 of this matter.

The MPUC has scheduled the case for hearing on July 31 and August 1, 2007. Phase 2 of the contested case is currently underway.

Renewable Energy Standard The 2007 Minnesota legislature adopted a Renewable Energy Standard (RES) requiring NSP-Minnesota to acquire 30 percent of its energy requirements by 2020 from qualifying renewable sources, of which 25 percent must be wind energy. The legislation allows all NSP-Minnesota renewable resources to count toward meeting the standard and provides greater flexibility toward meeting the standard. Costs associated with complying with the standard are recoverable through automatic recovery mechanisms.

Conservation and Demand-Side Management Legislation The 2007 Minnesota legislature adopted a bill establishing a statewide goal to reduce energy demand by 1.5 percent per year and fossil-fuel use by 15 percent. The bill requires utilities to propose conservation and demand-side management programs that achieve at least 1.0 percent per year reduction in energy demand, subject to certain limitations regarding excessive costs for customers, threatened reliability or other negative consequences. The bill also allows utilities to fund internal infrastructure changes that will contribute to lower energy use and provides for cost recovery outside a rate case for such projects.

NSP-Minnesota Base Load Acquisition Proceeding On Nov. 1, 2006, NSP-Minnesota filed a proposal with the MPUC for a purchase of 375 MW of capacity and energy from Manitoba Hydro for the period 2015-2025 and the purchase of 380 MW of wind energy to fulfill the base load need identified in the 2004 resource plan. The proposal included a signed term sheet with Manitoba Hydro and a process to acquire the wind energy. Alternative suppliers were entitled to submit competing proposals to the MPUC by Dec. 18, 2006. An alternate supplier proposed a 375 MW share of a lignite plant 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. On July 20, 2007, NSP-Minnesota filed a petition asking the ALJ to suspend the proceeding until NSP-Minnesota can complete analysis of the impact of the RES and conservation goals on its need for additional resources.

Additional Base Load Capacity Projects for Sherco, Monticello and Prairie Island NSP-Minnesota has committed to file for necessary approvals for projects to increase the capacity and provide additional base load generation from its Sherco, Monticello and Prairie Island generating facilities by Sept. 1, 2007. On July 20, 2007, NSP-Minnesota filed a Notice of Changed Circumstance with the MPUC seeking to delay these proceedings until NSP-Minnesota can complete analysis of the impact of the RES and conservation goals on its need for additional resources.

NSP-Minnesota Transmission Certificates of Need In December 2001, NSP-Minnesota proposed construction of various transmission system upgrades for up to 825 MW of renewable energy generation (wind and biomass) being constructed in southwest and western Minnesota. In March 2003, the MPUC granted four certificates of need to NSP-Minnesota, thereby approving construction, subject to certain conditions. The initial projected cost of the transmission upgrades was approximately $160 million.

The MPUC granted a routing permit for the first major transmission facilities in the development program in 2004. The remaining routing permit proceedings were completed in 2005.

In late 2006, NSP-Minnesota filed two applications for certificates of need with the MPUC for four additional transmission lines in southwestern Minnesota and Chisago County. On June 21, 2007, an ALJ recommended approval of the three 115 KV southwestern Minnesota projects. Evidentiary hearings regarding the Chisago County project are expected to commence in September 2007.

In addition, NSP-Minnesota along with ten other transmission providers, have announced plans to file certificate of need applications by Aug. 17, 2007, for three 345 KV transmission lines serving Minnesota and parts of surrounding states.

FCA Investigation In 2003, the MPUC opened an investigation to consider the continuing usefulness of fuel clause adjustments for electric utilities in Minnesota. There was no further activity until the MPUC issued a notice for comments on April 5, 2007, to continue the statewide investigation.

Pursuant to the notice, utilities in Minnesota, the MDOC and the OAG filed initial and reply comments on April 30, 2007 and June 1, 2007, respectively. The utilities generally argued the 2003 investigation could be closed, with remaining issues addressed in the separate investigation initiated by the Dec. 20, 2006 order in the MISO Day 2 cost recovery docket. The MPUC is now expected to decide whether to continue or close the 2003 investigation.

Other Regulatory Matters PSCo

***Renewable Energy Standard* -** The 2007 Colorado legislature adopted an increased Renewable Energy Standard that requires PSCo to generate or purchase 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. The new law limits the incremental retail rate impact from these acquisitions to 2 percent. The new legislation encourages favorable cost recovery for utility investment in renewable resources, including the use of a rider mechanism and a return on construction work in progress.

***Transmission Cost Recovery Legislation* -** The 2007 Colorado legislature enacted legislation that is intended to encourage investment in transmission infrastructure in Colorado. The new legislation provides for recovery through a rate rider of all costs a utility incurs in the planning, developing and construction or expansion of transmission facilities and for current recovery through this rider of the utilities weighted average cost of capital on transmission construction work in progress as of the end of the prior year. This legislation also provides for rate-regulated Colorado utilities to develop plans to construct or expand transmission facilities to transmission constrained zones where new electric generation facilities, including renewable energy facilities, are likely to be located and provides for expedited approvals for such facilities.

2003 Least Cost Plan (LCP) Investigation - In January 2007, PSCo filed with the CPUC its final report on its evaluation of the bids submitted in response to PSCo s 2005 All Source request for proposal under PSCo s 2003 LCP. In the report, PSCo stated it intended to negotiate extensions to power purchase agreements for the output from three existing gas-fired facilities for a total of 465 MW of the 896 MW needed for 2013. The final report explained that PSCo was intentionally waiting to fill the remaining 430MW resources needed in 2013 until PSCo s 2007 LCP and that PSCo was rejecting uneconomic bids received for new coal generation and for renewal of contracts with existing natural gas-fired generators.

On March 1, 2007, the CPUC issued an order requiring PSCo to apply for approval of a 2013 contingency plan. On April 2, 2007, PSCo filed its 2013 contingency plan, which recommended addressing the remaining 2013 resource need in the 2007 LCP to be filed in October 2007. PSCo s contingency plan also listed other options, which PSCo predicts will be less costly than accepting the uneconomic coal and natural gas bids.

On April 25, 2007, the CPUC asked its staff to provide the CPUC with a report that addresses at a minimum, whether the PSCo s negotiations with coal bidders were made in good faith; any specific concerns the staff may have with respect to PSCo s evaluation of 2013 resources; and what changes to the CPUC rules or practices may be warranted in light of the staff s conclusions.

The CPUC staff filed a report, which argues that the PSCo should have made more concessions to the coal bidders in contract negotiations and PSCo s conclusion that the coal bids were not economic was based upon flawed modeling. The CPUC staff recommends changes to the LCP rules that would require model contracts to be approved by the CPUC as part of the upfront LCP process and would require the CPUC to use an independent evaluator to identify the utility s least cost resource portfolio. Staff further recommends restrictions on resource modeling practices and assumptions and on utility actions that depart from an approved resource plan.

On May 25, 2007, PSCo amended its 2013 contingency plan to include amendments to two power purchase agreements with Tri-State Generation and Transmission Association, Inc. under which PSCo would return Tri-State generation capacity currently under contract to PSCo in the years 2009 through 2012 and then recapture that capacity in the years 2013 through 2015. PSCo explained this capacity swap would save PSCo an estimated $49 million on a net present value basis. PSCo still would meet the remaining 2013 need through its 2007 LCP. The CPUC held hearings on the PSCo 2013 contingency plan on July 9, 2007. The PSCo contingency plan was opposed by the CPUC trial staff and by a pro se intervenor, but was supported by the Colorado Office of Consumer Counsel. The opponents have asked for all 2013 resource acquisition decisions to be deferred to the 2007 LCP. A CPUC decision is not expected until mid-August 2007.

On July 3, 2007, the CPUC issued an order soliciting comments to determine whether the LCP Rules need to be changed on an emergency basis to govern utility filings in October 2007. PSCo filed comments responding to this order suggesting the LCP rules require revisions, but not the revisions suggested by the CPUC staff which include the recommendation of using an independent evaluator to assess all bids. CPUC action, if any, to issue emergency changes to the LCP rules is expected to occur in August 2007.

Other Regulatory Matters SPS

New Mexico Renewable Portfolio Standard - The 2007 New Mexico legislature enacted a renewable portfolio standard in which renewable energy must comprise no less than 5 percent of retail sales by 2006; 10 percent by 2011; 15 percent by 2015; and twenty percent by 2020. The legislation also allows performance-based incentives to encourage the acquisition of renewable energy supplies beyond the requirements. The NMPRC is in the process of implementing revised rules related to the increased requirements; performance-based incentives have been deferred to a future rulemaking process. The NMPRC has interpreted the diversification requirement to mean one in which no less than twenty percent of the standard requirement is met using wind energy, no less than twenty percent is met using solar energy, no less than ten percent is met using one or more of the other renewable energy technologies, and no less than ten percent is met through distributed generation.

Texas Renewable Energy Zone**s** - The PUCT is expected to designate competitive renewable energy zones (CREZs) later this summer. CREZs are regions of the state in which renewable energy resources and suitable land areas are sufficient to develop electric generating capacity from renewable energy technologies, such as wind. The PUCT will determine the availability of renewable resources in a candidate CREZ, the financial commitment of generators, and the major transmission improvements necessary to deliver the energy generated by renewable resources. A statewide study conducted by the Electric Reliability Council of Texas (ERCOT) identifies the Texas Panhandle as having the top four of the State s primary areas for wind energy expansion. Several transmission proposals have been filed in the CREZ proceeding, including plans to interconnect CREZs with the SPP, and plans that would collect wind energy from Panhandle CREZs and deliver it into ERCOT.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters at Note 6 to the consolidated financial statements.

Tax Matters

See a discussion of tax matters associated COLI policies at Note 4 to the consolidated financial statements for discussion of exposures regarding the tax deductibility of corporate-owned life insurance loan interest.

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, 2006, includes a list 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 pending accounting changes at Note 2 to the consolidated financial statements.

Financial Market Risks

Xcel Energy and its subsidiaries are exposed to market risks, including changes in commodity prices and interest rates, as disclosed in Management s Discussion and Analysis in its Annual Report on Form 10-K for the year ended Dec. 31, 2006. Commodity price risks for Xcel Energy s regulated subsidiaries are mitigated in most jurisdictions due to cost-based rate regulation. At June 30, 2007, there were no material changes to the financial market risks that affect the quantitative and qualitative disclosures presented as of Dec. 31, 2006, in Item 7A of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2006. Value-at-risk, commodity trading and hedging information is provided below for informational purposes.

NSP-Minnesota maintains trust funds, as required by the Nuclear Regulatory Commission, to fund certain costs of nuclear decommissioning. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. However, because the costs of nuclear decommissioning are recovered through NSP-Minnesota rates, fluctuations in investment fair value do not affect NSP-Minnesota s consolidated results of operations.

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.

As of June 30, 2007, the VaRs for the commodity trading operations were:

(Millions of Dollars)	Period Ended June 30, 2007	Change from Period Ended March 31, 2007	VaR Limit	Average	High	Low
Commodity Trading (1)	$ 0.38	$ (0.11)	$ 5.00	$ 0.41	$ 0.56	$ 0.26

(1) Comprises transactions for NSP-Minnesota, PSCo and SPS.

Commodity Trading and Hedging Activities

Xcel Energy and its subsidiaries engage in short-term wholesale and commodity trading activities that are accounted for in accordance with SFAS 133. Xcel Energy and its subsidiaries make wholesale purchases and sales of energy and energy-related products and natural gas in order to optimize the value of their electric generating facilities and retail supply contracts. Xcel Energy also engages in limited commodity trading activities. Xcel Energy utilizes various physical and financial contracts and instruments for the purchase and sale of energy, energy-related products, capacity, natural gas, transmission and natural gas transportation.

For the period ended June 30, 2007, these contracts and instruments, with the exception of transmission and natural gas transportation contracts, which meet the definition of a derivative in accordance with SFAS 133 were marked to market. Changes in fair value of commodity trading contracts that do not qualify for hedge accounting treatment are recorded in income in the reporting period in which they occur.

The changes to the fair value of the commodity trading contracts for the six months ended June 30, 2007 and 2006 were as follows (the commodity trading activity presented in the tables below also includes certain positions within the short-term wholesale activity which do not qualify for hedge accounting):

	Six months ended June 30,	
(Millions of Dollars)	**2007**	**2006**
Fair value of contracts outstanding at Jan. 1	$ (1.2)	$ 3.9
Contracts realized or otherwise settled during the period	(8.7)	(1.3)
Fair value of trading contract additions and changes during the period	13.6	6.8
Fair value of contracts outstanding at June 30	$ 3.7	$ 9.4

As of June 30, 2007, the sources of fair value of the commodity trading and hedging net assets are as follows:

Commodity Trading Contracts

(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	$ (13,355)	$	$	$	$ (13,355)
	2	14,667	743	586		15,996
PSCo	1	(422)				(422)
	2	1,678	1,569			3,247
SPS*	1	28				28
	2	39	11	1		51
Total Futures/Forwards Fair Value		$ 2,635	$ 2,323	$ 587	$	$ 5,545

(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
PSCo	2	$ (1,821)	$	$	$	$ (1,821)
SPS*	2	16				16
Total Options Fair Value		$ (1,805)	$	$	$	$ (1,805)

Commodity Hedge Contracts

(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	$ 4	$	$	$	$ 4
	2	29,539				29,539
PSCo	1	8				8
PSCo	2	3,523				3,523
NSP-Wisconsin	2	(231)				(231)
Total Futures/Forwards Fair Value		$ 32,843	$	$	$	$ 32,843

(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	$ 4,385	$	$	$	$ 4,385
PSCo	2	17,172				17,172
NSP-Wisconsin	2	399				399
Total Options Fair Value		$ 21,956	$	$	$	$ 21,956

(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.

* SPS conducts an inconsequential amount of commodity trading. Margins from commodity trading activity are partially redistributed to SPS, NSP-Minnesota, and PSCo, pursuant to the joint operating agreement (JOA) approved by the FERC. As a result of the JOA, margins received pursuant to the JOA are reflected as part of the fair values by source for the commodity trading net asset or liability balances.

Normal purchases and sales transactions, as defined by SFAS 133 and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not included in the commodity trading operations and are not qualifying hedges.

At June 30, 2007, a 10-percent increase in market prices over the next 12 months for trading contracts would decrease pretax income from continuing operations by approximately $0.2 million, whereas a 10-percent decrease would have an immaterial impact on pretax income from continuing operations.

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 policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At June 30, 2007, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $11.1 million annually, or approximately $2.8 million per quarter. See Note 9 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries interest rate swaps.

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 June 30, 2007, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $21.7 million, while a decrease of 10-percent would have resulted in a decrease of $16.8 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	Six months ended June 30, 2007	2006
Cash provided by operating activities		
Continuing operations	$ 910	$ 1,136
Discontinued operations	31	80
Total	$ 941	$ 1,216

Cash provided by operating activities for continuing operations decreased by $275 million for the first six months of 2007, compared with the first six months of 2006. This decrease was largely due to the timing of working capital activity. Specifically, the collection of receivables and the collection of recoverable purchased natural gas and electric energy costs. The decrease in cash provided by operations was partially offset by decreased cash expenditures for accounts payable.

(Millions of Dollars)	Six months ended June 30, 2007	2006
Cash provided by (used in) investing activities		
Continuing operations	$ (979)	$ (710)
Discontinued operations		42
Total	$ (979)	$ (668)

Cash used in investing activities for continuing operations increased by $311 million for the first six months of 2007, compared with the first six months of 2006. The increase was primarily due to increased capital expenditures. In addition, the cash flow used in investing activities reflects the sale of certain investments in the nuclear decommissioning trust fund and the reinvestment of the proceeds. The sale and reinvestment was part of a transaction intended to consolidate trust fund accounts into an income tax advantaged fund, resulting from the Energy Policy Act of 2005.

(Millions of Dollars)	Six months ended June 30, 2007	2006
Cash provided by (used in) financing activities		
Continuing operations	$ 55	$ (468)
Discontinued operations		
Total	$ 55	$ (468)

Cash used in financing activities for continuing operations decreased by $523 million for the first six months of 2007, compared with the first six months of 2006. The decrease was largely due to lower repayments of long-term debt in the first six months of 2007 compared to first six months of 2006.

Capital Sources

Xcel Energy and Utility Subsidiary Credit Facilities - As of July 24, 2007, 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	$ 22.8	$ 477.2	$ 0.3	$ 477.5	December 2011
PSCo	700	294.4	405.6	0.3	405.9	December 2011
SPS	250	117.0	133.0	5.8	138.8	December 2011
Xcel Energy Holding Company	800	258.2	541.8	3.3	545.1	December 2011
Total	$ 2,250	$ 692.4	$ 1,557.6	$ 9.7	$ 1,567.3	

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

The liquidity table reflects the payment of common dividends on July 20, 2007.

Short-Term Funding Sources **-** Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. Access to reasonably priced capital markets is dependent in part on credit agency reviews and ratings. The following ratings reflect the views of Moody s, Standard & Poor s, and 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 July 24, 2007, the following 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 Ratings Services and P-2 by Moody s Investor Services, Inc. The short-term credit ratings for Xcel Energy, PSCo and SPS are all rated F2, while NSP-Minnesota is rated F1 by Fitch Ratings.

As of June 30, 2007, 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 June 30, 2007, was $620.2 million at a weighted average yield of 5.43 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 June 30, 2007, and the SEC approved short-term borrowing limits from the money pool are as follows:

	Borrowings (Loans)	Total Borrowing Limits
NSP-Minnesota	$ (180.8)	$ 250 million
PSCo	99.0	250 million
SPS	81.8	100 million

Registration Statements In March 2007, PSCo filed a shelf registration statement with the SEC to register $1.2 billion of first mortgage bonds and unsecured debt securities.

Long-Term Borrowings - See a discussion of the long-term borrowings at Note 8 to the consolidated financial statements.

Future Financing Plans

During the third quarter of 2007, PSCo anticipates issuing up to $350 million of long-term debt securities to refinance a prior debt maturity and to fund capital expenditures.

NSP-Wisconsin may issue long-term debt for up to $125 million by year-end 2007.

Xcel Energy may issue a hybrid security of approximately $500 million by year-end 2007.

On June 29, 2007, NSP-Minnesota announced that it will redeem all of its outstanding 8.00 percent Notes, Series due 2042. The redemption will take place on Aug. 1, 2007. NSP-Minnesota will redeem the notes at a redemption price equal to 100 percent of the principal amount of the notes ($25.00), plus accrued and unpaid interest on the notes, if any, to the redemption date.

Earnings Guidance

Xcel Energy s 2007 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

	2007 Diluted Earnings Per Share Range
Utility operations	$ 1.45 - $1.55
Holding company financing costs and other	(0.15)
Xcel Energy Continuing Operations	**$1.30 - $1.40**
Discontinued operations PSRI earnings	$0.03 - $0.05
Discontinued operations PSRI COLI settlement	$(0.13)
Total Discontinued operations - COLI	**$(0.10) - $(0.08)**
Total Xcel Energy	**$ 1.20-$1.32**

Key Assumptions for 2007:

Normal weather patterns are experienced during the remainder of the year.

No material incremental accruals related to the SPS regulatory proceedings.

Reasonable rate recovery in the Minnesota natural gas rate case.

Weather-adjusted retail electric utility sales grow by approximately 1.4 percent to 2.0 percent.

Weather-adjusted retail firm natural gas sales grow by approximately 1.0 percent to 2.0 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 $25 million. Capacity costs at PSCo are recovered under the Purchased Capacity Cost Adjustment.

Utility operating and maintenance expenses increase between 2 percent and 3 percent.

Absent approval of the Minnesota depreciation filing, depreciation expense is projected to increase approximately $35 million to $45 million. If the Minnesota Commission approves NSP-Minnesota s request (as filed) to extend the depreciation life of the Monticello nuclear plant by 20 years, depreciation expense would increase $5 million to $15 million.

Interest expense increases approximately $30 million to $35 million.

Allowance for funds used during construction-equity increases approximately $15 million to $20 million.

The COLI settlement is approved by the Department of Justice Tax Division and the IRS.

The effective tax rate for continuing operations is approximately 31 percent to 34 percent.

Average common stock and equivalents total approximately 433 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 5 and 6 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 Note 14 of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2006 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 2006 Annual Report on Form 10-K, which is incorporated herein by reference. As a result of developments in our business since the filing of the 2006 Annual Report on Form 10-K, we are providing below an update of the risk factor relating to COLI.

Our subsidiary, PSCo, has received a notice from the IRS proposing to disallow certain interest expense deductions that PSCo claimed under a COLI policy. We have reached a settlement in principle. Should a settlement not be approved and the IRS ultimately prevails on this issue, our liquidity position and financial results could be materially adversely affected.

PSCo s wholly owned subsidiary PSRI owns and manages permanent life insurance policies on some of PSCo s employees, known as COLI. At various times, borrowings have been made against the cash values of these COLI policies and deductions taken on the interest expense on these borrowings. The IRS has challenged the deductibility of such interest expense deductions and has disallowed the deductions taken in tax years 1993 through 2003.

In April 2004, Xcel Energy filed a lawsuit against the U.S. government in the U.S. District Court for the District of Minnesota to establish its right to deduct the interest expense that had accrued during tax years 1993 and 1994 on policy loans related to its COLI policies that insured certain lives of PSCo employees. These policies are owned by PSRI, a wholly owned subsidiary of PSCo.

After Xcel Energy filed this suit, the IRS sent three statutory notices of deficiency of tax, penalty and interest for 1995 through 2002. Xcel Energy has filed U.S. Tax Court petitions challenging those notices. PSRI also continued to take deductions for interest expense on policy loans for subsequent years. The total exposure for the tax years in dispute and through 2007 is approximately $583 million, which includes income tax, interest and potential penalties.

On June 19, 2007, a settlement in principle was reached between Xcel Energy and representatives of the United States Government that would resolve this dispute. The terms of the proposed settlement are as follows:

Xcel Energy would pay the IRS $64.4 million (or approximately $56 million, net, after tax) in full settlement of all of the government s claims for additional taxes, interest and penalties relating to these COLI plans for tax years 1993-2007.

Xcel Energy would further agree to claim no additional deductions resulting from its COLI plans for any tax year after 2007 and to surrender its policies when the offer has been accepted in writing by the government.

The government would permit Xcel Energy to surrender these policies without incurring any tax liability on any gain from that surrender.

This settlement requires final approval from the IRS and the Department of Justice (DOJ). There is no guarantee that such approvals will be obtained.

Among other things, the settlement process requires Xcel Energy to submit a written settlement offer setting forth the basic terms and for the DOJ Tax Division and the IRS to review that offer before they decide to accept or reject it. Xcel Energy submitted this settlement offer to the government on July 2, 2007.

It is expected that a final decision on the settlement will be reached during Xcel Energy s third quarter of 2007.

Should the settlement not be approved and the IRS ultimately prevails, tax and interest payable through June 30, 2007, would reduce earnings by an estimated $450 million. Xcel Energy had received formal notification that the IRS would seek penalties. If penalties (plus associated interest) also are included, the total estimated exposure through June 30, 2007, is estimated to be approximately $538 million.

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

None.

Item 4. Submission of Matters to a Vote of Security Holders

Xcel Energy s Annual Meeting of Shareholders was held on May 23, 2007, for the purpose of voting on the matters listed below. Proxies for the meeting were solicited pursuant to Section 14(a) of the Securities Exchange Act of 1934, and there were no solicitations in opposition to management s solicitations. All of management s nominees for directors as listed in the proxy statement were elected. The voting results are as follows:

1. Proposal to elect thirteen directors:

Election of Director	Shares Voted For	Withheld Authority
C. Coney Burgess	340,864,861	8,060,999
Fredric W. Corrigan	341,266,545	7,659,315
Richard K. Davis	262,323,069	86,602,791
Roger R. Hemminghaus	340,978,899	7,946,961
A. Barry Hirschfeld	340,956,718	7,969,142
Richard C. Kelly	340,195,602	8,730,258
Douglas W. Leatherdale	336,351,989	12,573,871
Albert F. Moreno	341,344,738	7,581,122
Dr. Margaret R. Preska	339,714,081	9,211,779
A. Patricia Sampson	339,983,803	8,942,057
Richard H. Truly	340,924,195	8,001,665
David A. Westerlund	341,201,288	7,724,572
Timothy V. Wolf	341,276,275	7,649,585

2. Proposal to ratify the appointment of Deloitte & Touche LLP as Xcel Energy s independent registered public accountants for 2007:

Shares Voted For	Shares Voted Against	Shares Abstained
340,818,050	3,246,622	4,861,188

3. Shareholder proposal Separate the roles of the Chairman of the Board and CEO:

Shares Voted For	Shares Voted Against	Shares Abstained	Broker Non Vote
92,332,349	160,512,387	7,740,390	88,340,734

4. Shareholder proposal Performance criteria for executive compensation plans:

Shares Voted For	Shares Voted Against	Shares Abstained	Broker Non Vote
41,167,838	191,361,367	28,055,921	88,340,734

Item 6. Exhibits

The following Exhibits are filed with this report:

4.01	Supplemental Indenture, dated June 1, 2007, between Northern States Power Co. (a Minnesota corporation) and BNY Midwest Trust Company, as successor Trustee. (Exhibit 4.01 to NSP-Minnesota Form 8-K (file no. 001-31387) dated June 19, 2007).
10.01	Second Amendment to the Xcel Energy Senior Executive Severance and Change-in-Control Policy (Exhibit 10.01 to Xcel Energy s Form 8-K (file no 1-3034) and incorporated herein by reference).
10.02	Amendment Four to Employment Agreement Between Xcel Energy Inc. and Paul Bonavia (Exhibit 10.02 to Xcel Energy s Form 8-K (file no 1-3034) and incorporated herein by reference).
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

July 27, 2007