XCEL ENERGY INC
Form 10-Q
October 26, 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 Sept. 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	**41-0448030**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
414 Nicollet Mall, Minneapolis, Minnesota	**55401**
(Address of principal executive offices)	(Zip Code)

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 Oct. 19, 2007
Common Stock, $2.50 par value	419,930,078 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 Sept. 30, 2007	Three Months Ended Sept. 30, 2006	Nine Months Ended Sept. 30, 2007	Nine Months Ended Sept. 30, 2006
Operating revenues				
Electric utility	$ 2,199,533	$ 2,159,844	$ 5,935,031	$ 5,792,287
Natural gas utility	184,161	230,293	1,442,451	1,519,423
Nonregulated and other	16,303	21,454	53,469	61,858
Total operating revenues	2,399,997	2,411,591	7,430,951	7,373,568
Operating expenses				
Electric fuel and purchased power utility	1,101,844	1,160,896	3,113,314	3,106,804
Cost of natural gas sold and transported utility	89,245	136,795	1,049,601	1,156,042
Cost of sales nonregulated and other	4,452	4,096	14,179	16,763
Other operating and maintenance expenses utility	443,599	410,063	1,338,934	1,286,426
Other operating and maintenance expenses nonregulated	7,403	8,292	19,434	20,470
Depreciation and amortization	191,663	208,657	619,770	614,982
Taxes (other than income taxes)	66,021	71,551	210,432	221,410
Total operating expenses	1,904,227	2,000,350	6,365,664	6,422,897
Operating income	495,770	411,241	1,065,287	950,671
Interest and other income, net (see Note 10)	6,448	5,582	15,503	15,975
Allowance for funds used during construction - equity	9,023	8,300	25,294	16,752
Interest charges and financing costs				
Interest charges includes other financing costs of $4,924, $6,165, $16,518 and $18,770, respectively	137,432	121,715	390,407	360,297
Allowance for funds used during construction - debt	(8,481)	(8,363)	(24,129)	(22,245)
Total interest charges and financing costs	128,951	113,352	366,278	338,052
Income from continuing operations before income taxes	382,290	311,771	739,806	645,346
Income taxes	135,945	97,923	255,178	190,289
Income from continuing operations	246,345	213,848	484,628	455,057
Income (loss) from discontinued operations, net of tax (see Note 3)	5,369	10,614	(37,202)	18,978
Net income	251,714	224,462	447,426	474,035
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180
Earnings available to common shareholders	$ 250,654	$ 223,402	$ 444,246	$ 470,855
Weighted average common shares outstanding (thousands)				
Basic	419,822	406,123	413,555	405,234
Diluted	433,387	430,000	432,811	429,095
Earnings per share basic				
Income from continuing operations	$ 0.58	$ 0.52	$ 1.16	$ 1.12
Income (loss) from discontinued operations	0.02	0.03	(0.09)	0.04
Earnings per share basic	$ 0.60	$ 0.55	$ 1.07	$ 1.16
Earnings per share diluted				

Income from continuing operations	$	0.57	$	0.50	$	1.13	$	1.08
Income (loss) from discontinued operations		0.01		0.03		(0.08)		0.04
Earnings per share diluted	$	0.58	$	0.53	$	1.05	$	1.12
Cash dividends declared per common share	$	0.23	$	0.22	$	0.68	$	0.66

See Notes to Consolidated Financial Statements

3

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(Thousands of Dollars)

	Nine Months Ended Sept. 30, 2007	Nine Months Ended Sept. 30, 2006
Operating activities		
Net income	$ 447,426	$ 474,035
Remove loss (income) from discontinued operations	37,202	(18,978)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	645,007	643,520
Nuclear fuel amortization	38,570	35,359
Deferred income taxes	189,334	(117,707)
Amortization of investment tax credits	(7,282)	(7,354)
Allowance for equity funds used during construction	(25,294)	(16,752)
Undistributed equity in earnings of unconsolidated affiliates	(1,632)	(2,171)
Share-based compensation expense	14,996	19,044
Net realized and unrealized hedging and derivative transactions	(16,269)	(57,327)
Changes in operating assets and liabilities (net of effects of consolidation of NMC, see Note 14):		
Accounts receivable	104,876	242,288
Accrued unbilled revenues	19,655	208,359
Inventories	(25,223)	(6,620)
Recoverable purchased natural gas and electric energy costs	207,586	273,239
Other current assets	3,289	4,505
Accounts payable	(249,371)	(341,283)
Net regulatory assets and liabilities	(34,127)	36,246
Other current liabilities	197	166,918
Change in other noncurrent assets	(19,374)	(18,583)
Change in other noncurrent liabilities	(9,435)	(72,014)
Operating cash flows provided by discontinued operations	84,242	151,590
Net cash provided by operating activities	1,404,373	1,596,314
Investing activities		
Utility capital and construction expenditures	(1,481,693)	(1,165,807)
Allowance for equity funds used during construction	25,294	16,752
Purchase of investments in external decommissioning fund	(499,991)	(699,593)
Proceeds from the sale of investments in external decommissioning fund	467,447	665,814
Nonregulated capital expenditures and asset acquisitions	(958)	(1,614)
Proceeds from sale of assets		24,670
Cash obtained from consolidation of NMC (see Note 14)	38,950	
Change in restricted cash	(4,881)	(3,085)
Other investments	2,438	9,238
Investing cash flows provided by discontinued operations		42,377
Net cash used in investing activities	(1,453,394)	(1,111,248)
Financing activities		
Short-term repayments net	(206,075)	(396,120)
Proceeds from issuance of long-term debt	1,162,404	882,578
Repayment of long-term debt, including reacquisition premiums	(290,243)	(773,901)
Early participation payments on debt exchange (see Note 8)	(4,859)	
Proceeds from issuance of common stock	8,970	7,747
Dividends paid	(281,249)	(267,228)
Net cash provided by (used in) financing activities	388,948	(546,924)

Net increase (decrease) in cash and cash equivalents		339,927		(61,858)
Net increase (decrease) in cash and cash equivalents - discontinued operations		(16,517)		22,660
Cash and cash equivalents at beginning of year		37,458		71,382
Cash and cash equivalents at end of quarter	$	360,868	$	32,184
Supplemental disclosure of cash flow information:				
Cash paid for interest (net of amounts capitalized)	$	309,620	$	307,922
Cash paid for income taxes (net of refunds received)		(11,163)		(773)
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	69,192	$	43,068
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	45,791	$	44,338
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)

	Sept. 30, 2007	Dec. 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 360,868	$ 37,458
Accounts receivable, net of allowance for bad debts of $41,918 and $36,689, respectively	750,131	816,093
Accrued unbilled revenues	494,645	514,300
Materials and supplies inventories	164,258	158,721
Fuel inventories	118,270	95,651
Natural gas inventories	248,841	251,818
Recoverable purchased natural gas and electric energy costs	51,014	258,600
Derivative instruments valuation	116,319	101,562
Prepayments and other	189,135	189,658
Current assets held for sale and related to discontinued operations	161,470	229,633
Total current assets	2,654,951	2,653,494
Property, plant and equipment, at cost:		
Electric utility plant	20,140,069	19,367,671
Natural gas utility plant	2,925,672	2,846,435
Common utility and other property	1,476,783	1,439,020
Construction work in progress	1,715,364	1,425,484
Total property, plant and equipment	26,257,888	25,078,610
Less accumulated depreciation	(10,090,852)	(9,670,104)
Nuclear fuel, net of accumulated amortization: $1,276,488 and $1,237,917, respectively	179,101	140,152
Net property, plant and equipment	16,346,137	15,548,658
Other assets:		
Nuclear decommissioning fund and other investments	1,346,946	1,271,362
Regulatory assets	1,182,927	1,189,145
Prepaid pension asset	618,397	586,712
Derivative instruments valuation	399,198	437,520
Other	127,674	135,746
Noncurrent assets held for sale and related to discontinued operations	147,969	162,586
Total other assets	3,823,111	3,783,071
Total assets	$ 22,824,199	$ 21,985,223
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 306,997	$ 336,411
Short-term debt	420,225	626,300
Accounts payable	873,200	1,100,600
Taxes accrued	234,609	271,691
Dividends payable	97,644	91,685
Derivative instruments valuation	86,910	83,944
Other	397,747	347,809
Current liabilities held for sale and related to discontinued operations	63,332	26,149
Total current liabilities	2,480,664	2,884,589
Deferred credits and other liabilities:		
Deferred income taxes	2,458,052	2,264,164
Deferred investment tax credits	114,312	121,594
Asset retirement obligations	1,301,083	1,361,951
Regulatory liabilities	1,401,863	1,364,657
Pension and employee benefit obligations	657,560	704,913
Derivative instruments valuation	436,562	483,077

Customer advances	303,929	302,168
Other liabilities	128,575	119,633
Noncurrent liabilities held for sale and related to discontinued operations	22,012	5,477
Total deferred credits and other liabilities	6,823,948	6,727,634
Minority interest in subsidiaries	307	1,560
Commitments and contingent liabilities (see Note 6)		
Capitalization:		
Long-term debt	7,252,800	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: Sept. 30, 2007 419,925,576; Dec. 31, 2006 407,296,907	6,161,500	5,816,822
Total liabilities and equity	$ 22,824,199	$ 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					
	Shares	**Par Value**	**Additional Paid In Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total Common Stockholders Equity**
Three months ended Sept. 30, 2007 and 2006						
Balance at June 30, 2006	405,560	$ 1,013,901	$ 4,012,799	$ 632,263	$ (103,713)	$ 5,555,250
Net income				224,462		224,462
Minimum pension liability adjustment, net of tax of $21					(21)	(21)
Net derivative instrument fair value changes during the period, net of tax of $(11,309) (see Note 9)					(15,966)	(15,966)
Unrealized gain - marketable securities, net of tax of $8					15	15
Comprehensive income for the period						208,490
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(90,451)		(90,451)
Issuances of common stock	965	2,411	13,551			15,962
Share-based compensation			(1,286)			(1,286)
Balance at Sept. 30, 2006	406,525	$ 1,016,312	$ 4,025,064	$ 765,214	$ (119,685)	$ 5,686,905
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 779,603	$ (9,294)	$ 5,994,916
Net income				251,714		251,714
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $115 (see Note 12)					446	446
Net derivative instrument fair value changes during the period, net of tax of $1,042 (see Note 9)					(2,235)	(2,235)
Comprehensive income for the period						249,925
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(96,582)		(96,582)

Issuances of common stock	416		1,040		7,644						8,684
Share-based compensation					5,617						5,617
Balance at Sept. 30, 2007	419,926	$	1,049,814	$	4,189,094	$	933,675	$	(11,083)	$	6,161,500

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					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
Nine months ended Sept. 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				474,035		474,035
Minimum pension liability adjustment, net of tax of $21					(21)	(21)
Net derivative instrument fair value changes during the period, net of tax of $6,779 (see Note 9)					12,354	12,354
Unrealized gain - marketable securities, net of tax of $25					43	43
Comprehensive income for the period						486,411
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(267,779)		(267,779)
Issuances of common stock	3,138	7,844	48,841			56,685
Share-based compensation			19,513			19,513
Balance at Sept. 30, 2006	406,525	$ 1,016,312	$ 4,025,064	$ 765,214	$ (119,685)	$ 5,686,905
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				447,426		447,426
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $345 (see Note 12)					1,339	1,339
Net derivative instrument fair value changes during the period, net of tax of $2,926 (see Note 9)					3,900	3,900
Unrealized gain - marketable securities, net of tax of $2					4	4
Comprehensive income for the period						452,669
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(284,027)		(284,027)
Issuances of common stock	12,629	31,572	129,072			160,644
Share-based compensation			16,365			16,365
Balance at Sept. 30, 2007	419,926	$ 1,049,814	$ 4,189,094	$ 933,675	$ (11,083)	$ 6,161,500

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 Sept. 30, 2007, and Dec. 31, 2006; the results of its operations and changes in stockholders equity for the three and nine months ended Sept. 30, 2007 and 2006; and its cash flows for the nine months ended Sept. 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.

On Aug. 8, 2007, Xcel Energy filed a Current Report on form 8-K to update historical financial information included in Xcel Energy s Annual Report on form 10-K for the year ended Dec. 31, 2006 to present PSR Investments, Inc. (PSRI), a wholly-owned subsidiary of Public Service Company of Colorado (PSCo) as a discontinued operation.

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 Current Report on Form 8-K filed on Aug. 8, 2007, 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 with the United States government and management s decision to surrender all corporate-owned life insurance (COLI) policies following acceptance in writing of the offer by the government, all the amounts related to PSRI have been classified as discontinued operations. See Notes 3 and 4 for additional disclosure related to discontinued operations and the COLI settlement. Financial data for PSRI has been presented as discontinued operations as outlined in Note 3. 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.

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.

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, 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 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 the tax deductibility of interest expense associated with PSCo s COLI policies. Xcel Energy started to report earnings from PSRI and the settlement costs as discontinued operations in the second quarter of 2007, as a result of the settlement in principle and management s decision to surrender the COLI policies, following acceptance in writing of the offer by the government.

On Sept. 20, 2007, Xcel Energy submitted its formal offer in compromise to settle the dispute relating to the proper tax treatment of the COLI policies beginning with tax year 1993 and for all years thereafter. On Sept. 21, 2007, the United States accepted the terms of that settlement offer. The terms of the final settlement are essentially the same as the settlement in principle reached on June 19, 2007. The government s letter terminates the tax litigation pending between the parties for tax years 1993-2002 and also specifies the agreed tax treatment for certain aspects of those policies for subsequent tax years. See Note 4 for additional disclosure related to the 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 Sept. 30, 2007				
Operating revenues	$	$	$	$
Operating expense (income), interest and other income, net	6,579		(1,172)	5,407

Pretax (loss) income from discontinued operations		(6,579)				1,172		(5,407)
Income tax expense (benefit)		(11,851)		(79)		1,154		(10,776)
Net income from discontinued operations	$	5,272	$	79	$	18	$	5,369
Three months ended Sept. 30, 2006								
Operating revenues	$		$		$	1,374	$	1,374
Operating expense, interest and other income, net		4,571				2,583		7,154
Pretax loss from discontinued operations		(4,571)				(1,209)		(5,780)
Income tax benefit		(14,898)		(1,068)		(428)		(16,394)
Net income (loss) from discontinued operations	$	10,327	$	1,068	$	(781)	$	10,614

(Thousands of dollars)	PSRI	Utility Segments	All Other	Total
Nine months ended Sept. 30, 2007				
Operating revenues	$	$	$ 36	$ 36
Operating expense (income), interest and other income, net	58,910		(2,971)	55,939
Pretax (loss) income from discontinued operations	(58,910)		3,007	(55,903)
Income tax expense (benefit)	(19,332)	(81)	712	(18,701)
Net (loss) income from discontinued operations	$ (39,578)	$ 81	$ 2,295	$ (37,202)
Nine months ended Sept. 30, 2006				
Operating revenues	$	$	$ 6,212	$ 6,212
Operating expense (income), interest and other income, net	16,524	(18)	8,748	25,254
Pretax (loss) income from discontinued operations	(16,524)	18	(2,536)	(19,042)
Income tax benefit	(33,390)	(2,233)	(2,397)	(38,020)
Net income (loss) from discontinued operations	$ 16,866	$ 2,251	$ (139)	$ 18,978

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

(Thousands of dollars)	Sept. 30, 2007	Dec. 31, 2006
Cash	$ 9,212	$ 25,729
Accounts receivables, net	4,414	2,998
Deferred income tax benefits	104,884	160,456
Other current assets	42,960	40,450
Current assets held for sale and related to discontinued operations	$ 161,470	$ 229,633
Net property, plant and equipment	$	$ 174
Deferred income tax benefits	126,525	152,133
Other noncurrent assets	21,444	10,279
Noncurrent assets held for sale and related to discontinued operations	$ 147,969	$ 162,586
Accounts payable	$ 3,636	$ 2,230
Other current liabilities	59,696	23,919
Current liabilities held for sale and related to discontinued operations	$ 63,332	$ 26,149
Other noncurrent liabilities	$ 22,012	$ 5,477
Noncurrent liabilities held for sale and related to discontinued operations	$ 22,012	$ 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 the lives of certain 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 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 1993 through 2007 was approximately $583 million, which included income tax, interest and potential penalties.

On June 19, 2007, Xcel Energy and the United States reached a settlement in principle regarding this dispute.

On Sept. 20, 2007, Xcel Energy submitted its formal offer in compromise and by letter dated Sept. 21, 2007, the United States accepted the terms of that settlement offer. The terms of the final settlement are essentially the same as the settlement in principle reached on June 19, 2007. The U.S. government s letter terminates the tax litigation pending between the parties for tax years 1993-2002 and also specifies the agreed tax treatment for certain aspects of those policies for subsequent tax years.

The essential financial terms of the final settlement, as accepted, are as follows:

1. Xcel Energy will pay the government a total of $64.4 million in full settlement of the government s claims for tax, penalty, and interest for tax years 1993-2007.

2. Xcel Energy will pay that settlement amount as follows:

$32.2 million of that amount will be satisfied by tax and interest amounts that Xcel Energy has paid or is deemed under the terms of the settlement to have made to the government with respect to tax years 1993 and 1994.

Xcel Energy will satisfy the remaining settlement amount owed by paying the government $32.2 million by Oct. 31, 2007.

3. The total settlement amount will be allocated toward specified amounts of tax, penalty, and interest owed for 1993 and 1994 and other amounts of tax and interest owed for 1995.

4. Except as stated above, Xcel Energy will be entitled to claim COLI-related interest deductions for tax years 1995-2007.

5. Xcel Energy will surrender the policies to its insurer by Oct. 31, 2007 without having to recognize a taxable gain on the surrender.

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) In July 2006, the FASB issued FIN 48, which prescribes how a company should recognize, measure, present and disclose uncertain tax positions that such 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 was 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 Sept. 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 has been 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 final settlement regarding this litigation (see above discussion of COLI).

Xcel Energy is also currently under examination by the state of Colorado for years 2002 through 2005, the state of Minnesota for years 1998 through 2000, the state of Texas for years 2003 through 2005, and the state of Wisconsin for years 2002 through 2005. No material adjustments have been proposed as of Sept. 30, 2007 in the states of Colorado, Minnesota, Texas and Wisconsin. As of Sept. 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-2002, Minnesota-1998, Texas-2003, 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 $42.5 million (including $4.3 million reported as discontinued operations) on Sept. 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 $38.3 million on Sept. 30, 2007 (including $29.4 million reported as discontinued operations).

Included in the unrecognized tax benefit balance for continuing operations was $12.7 million and $6.1 million of tax positions on Jan. 1, 2007 and Sept. 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 $32.1 million of tax positions on Jan. 1, 2007 and Sept. 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 of $5.7 million from July 1, 2007 to Sept. 30, 2007, was due to the addition of similar uncertain tax positions relating to third 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.

Interventions and comments regarding the Aug. 1, 2007 cost allocation filings were submitted on Sept. 17, 2007.

The change in the unrecognized tax benefit balance for discontinued operations of $12.4 million from July 1, 2007 to Sept. 30, 2007 was due to the final 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 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 potential change.

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 Sept. 30, 2007, was not material. No amounts were accrued for penalties as of Sept. 30, 2007.

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 Open Access 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 reliability 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 sub-regional 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.. On Nov. 29, 2006, the FERC issued an order 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. The appeal remains pending.

In addition, in October 2006, MISO filed additional changes to its TEMT to regionalize future recovery of certain economic 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.

Transmission service rates in the MISO region presently use a rate design in which the transmission cost depends on the location of the load being served (referred to as license plate rates). Costs of existing transmission facilities are thus not regionalized. MISO and its transmission owners filed a successor rate methodology in Aug. 1, 2007, to be effective Feb. 1, 2008, as required by the 1998 agreement among transmission owners creating the MISO.

MISO and most vertically integrated transmission owners proposed to continue license plate rates for existing facilities. The March 15, 2007 FERC orders regarding RECBI and RECBII also require MISO to re-examine the cost allocation for new reliability improvements and economic projects in the Aug. 1, 2007 filing. MISO and most transmission owners proposed continued use of RECB I and RECB II for new facilities. Certain parties proposed to modify RECB I and RECBII to regionalize the cost of all new transmission facilities 345 KV and above. Interventions and comments regarding the Aug. 1, 2007 cost allocation filings were submitted on Sept. 17, 2007.

In addition, on Sept. 17, 2007, American Electric Power (AEP) filed a complaint asking FERC to order regionalized cost recovery of certain existing 500 KV and 765 KV facilities located in the PJM Interconnection, Inc. (PJM), another Regional Transmission Organization (RTO), and the cost of new facilities 345 KV and above in PJM and MISO over both the PJM and MISO regions effective Oct. 1, 2007. Interventions and protests to the AEP complaint will be filed by Oct. 29, 2007.

Proposals to regionalize transmission costs could shift the costs of transmission investments by Northern States Power Co., a Minnesota corporation (NSP-Minnesota) and Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin) to other MISO transmission service customers, but would also shift the costs of transmission investments of other participants in MISO or PJM to the combined systems of NSP-Minnesota and NSP-Wisconsin, which are managed as an integrated system and jointly referred to as the NSP System. Xcel Energy has estimated the regional rate design proposed by AEP for existing facilities would shift approximately $2.5 million in annual transmission costs to the NSP System. The impact of the regionalization of future facilities would depend on the specific facilities placed in service. NSP-Wisconsin and NSP-Minnesota intend to oppose certain aspects of the AEP proposal.

MISO Ancillary Services Market On Sept. 14, 2007, MISO filed an application with FERC to establish a regional ancillary services market (ASM), whereby MISO would provide bid-based-regulation and contingency operating reserve markets as an expansion of the regionalized wholesale energy sales market. The ASM is proposed to be effective in June 2008. Xcel Energy generally supports implementation of the ASM, since it is expected to allow NSP System generation to be used more efficiently because certain generation will not always need to be held in reserve, and the ASM is expected to facilitate the operation of wind generation on the NSP System required to achieve state-mandated renewable energy supply standards. The ASM proposal is pending FERC action.

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 MISO customers and paid to generators. 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.

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 Sept. 30, 2007, Xcel Energy has recorded an accrual of $1.8 million for this matter.

Five parties have filed separate Petitions for Review at the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) seeking judicial review of the FERC s determinations of the allocation of RSG costs among MISO market participants. Xcel Energy has intervened in each of these proceedings. On Aug. 16, 2007, the D.C. Circuit dismissed two of these Petitions for Review as incurably premature because the relevant petitioners also had pending requests for rehearing before the FERC. The remaining appeals are currently being held in abeyance subject to the resolution of the FERC proceedings.

On Aug. 10, 2007, Ameren Services Company (Ameren) and the Northern Indiana Public Service Company (NIPSCO) filed a joint complaint against MISO at FERC, challenging the MISO s current FERC-approved methodology for the recovery of RSG costs. Subsequently, on Aug. 17, 2007 and Aug. 24, 2007, Great Lakes Utilities, Indiana Municipal Power Agency, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Prairie Power, Inc., Southern Minnesota Municipal Power Agency and Wisconsin Public Power Inc. (collectively, Midwest TDUs), and Wabash Valley Power Association, Inc. (Wabash), respectively, filed complaints at the FERC effectively adopting the substantive arguments raised by Ameren and NIPSCO. The Midwest TDUs and Wabash explained that they filed their complaints to protect their own interests in the event that the complaint filed by Ameren and NIPSCO was dismissed by the FERC. Xcel Energy has moved to intervene in each of these proceedings. All three of these complaints are currently pending at FERC.

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. The Count of Appeals will hold a non-oral conference on the appeal on Dec. 4, 2007. No oral argument will be heard and the parties are not allowed to attend the conference. Unless an extension is granted, a decision will be issued by the count within ninety days from the date of the non-oral conference.

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 annually, which represented an increase of 2.4 percent. The request was 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 Aug. 16, 2007, the MPUC voted to approve a rate increase of approximately $11.9 million, based on an authorized ROE of 9.71 percent and an equity ratio of 51.98 percent. The written order was issued on Sept. 10, 2007.

On Oct. 1, 2007, NSP-Minnesota sought rehearing on the ROE issue, asking that the MPUC award a higher return consistent with precedent. The Minnesota Office of the Attorney General (MOAG) opposed this request. Rehearing is pending MPUC action. The MPUC has until Nov. 29, 2007, to reconsider its order, or NSP-Minnesota's petition for rehearing will be deemed denied and the Sept. 10, 2007, order will be final.

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 administraitive charges, through its fuel clause adjustment (FCA) effective April 1, 2005.

NSP-Minnesota is refunding Schedule 16 and 17 costs recovered through the FCA in 2005 ($4.4 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 MOAG 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 filed briefs urging 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 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. On March 8, 2007, the MPUC voted to approve the recommendation of the Minnesota Department of Commerce (MDOC) to allow recovery of $11.5 million in 2007.

On Aug. 31, 2007, NSP-Minnesota filed for approval of recovery of $19.7 million in Minnesota retail electric rates in 2008 under the TCR tariff. The Aug. 31, 2007 filing is pending written comments and MPUC action.

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 in 2007 outside a general rate case. The Feb. 28, 2007 filing is pending SDPUC action.

On Sept. 28, 2007, NSP-Minnesota and NSP-Wisconsin jointly filed proposed changes to the MISO TEMT to modify the wholesale formula transmission rate applicable to the NSP System to change from a historic test year to a forward-looking test year and provide for current recovery of a return on construction work in progress (CWIP) on certain new transmission investments. The proposed rate change would be effective Jan. 1, 2008. If approved by FERC, the change would not affect 2007 results, but would be expected to generate approximately $2.7 million of additional wholesale transmission service revenues in 2008 and additional annual increases in future years as NSP-Minnesota and NSP-Wisconsin work to complete their planned investment of approximately $1 billion in additional transmission plant by 2012. The filing is pending intervenor comments and FERC action.

Renewable Energy Standard Rider In June 2007, NSP-Minnesota filed an application for a new rate rider to recover the costs associated with utility-owned projects implemented in compliance with the Renewable Energy Standard adopted by the 2007 Minnesota Legislature. The proposed rate adjustment would recover the costs associated with the Grand Meadow wind farm, a 100-MW wind project proposed by NSP-Minnesota. The rate rider would recover the 2008 revenue requirements associated with the project of approximately $14.6 million. MPUC consideration of the certificate of need and site certificate needed for the Grand Meadow project is expected before year end. On Oct. 2, 2007, the MDOC filed comments recommending approval of the certificate of need, and no party has filed opposing comments as of this time.

Fixed Bill Complaint In January 2007, the MOAG 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 allowing low income housing energy assistance program customers 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 has filed to terminate the program after the current year, and is informing the appropriate customers of their ability to exit the program. In addition, NSP-Minnesota was directed to attempt to resolve all stranded cost issues with the MOAG. If a settlement with the MOAG was not reached, NSP-Minnesota could submit a proposal to the MPUC for resolution. A settlement was not reached. On July 6, 2007, NSP-Minnesota filed its proposal to resolve the phase out of the program, which includes allowing early exit to an identified group of customers whose actual usage varied significantly from that assumed in the fixed bill quote and recovery of all stranded costs associated with both early termination of the program and the exit of the affected low-income and low usage customers. The MOAG disputes recovery of stranded costs and recommends continued investigation. This matter is still pending before the MPUC with a decision expected later this year. Xcel Energy does not expect the complaint to have a material impact on the consolidated financial statements.

Mercury Cost Recovery On Dec. 29, 2006, NSP-Minnesota requested approval of a Mercury Emissions Reduction Rider . 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. It was the MDOC's position that NSP-Minnesota must file the environmental improvement plans required in compliance with the 2006 Mercury Reduction Act before this filing could be approved. NSP-Minnesota subsequently withdrew the filing and obtained approval to defer costs associated with its compliance with the 2006 Mercury Reduction Act as a regulatory asset for potential future recovery.

Annual Automatic Adjustment Report for 2006 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. NSP-Minnesota filed reply comments arguing 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 MDOC filed reply comments on Oct. 19, 2007 indicating that the cost assignment issues raised in initial comments have been resolved but raising other issues. NSP-Minnesota anticipates filing reply comments responding to the MDOC's new recommendations. The 2006 annual automatic adjustment report is pending final MPUC action.

Annual Automatic Adjustment Report for 2007 On Sept. 4, 2007, NSP-Minnesota filed its annual automatic adjustment report for the period from July 1, 2006 through June 30, 2007, which is the basis for the MPUC review of charges that flow through the FCA mechanism. During that time period, $1.16 billion in fuel and purchased energy costs, including $384 million of MISO Day 2 energy market charges were recovered from customers. The 2007 annual automatic adjustment report is pending MDOC comments and MPUC action.

Annual Review of Remaining Lives Depreciation Filing On June 4, 2007, NSP-Minnesota recommended lengthening the life of the Monticello nuclear plant by 20 years, effective Jan. 1, 2007 as well as certain other smaller life adjustments, as part of its annual review of remaining lives depreciation filing.

On Sept. 20, 2007, the MPUC approved NSP-Minnesota s remaining lives depreciation filing lengthening the life of the Monticello nuclear plant by 20 years, effective Jan. 1, 2007, as well as certain other smaller life adjustments. These adjustments, of approximately $31 million, have been reflected in NSP-Minnesota s consolidated financial statements for the quarter and period ended Sept. 30, 2007, as a reduction of depreciation expense. The MPUC also approved an adjustment to rate base to be used in the next electric rate case that will hold ratepayers indifferent to this change in remaining lives between rate cases. NSP-Minnesota calculated the revenue requirement associated with this adjustment to be approximately $1.4 - $2.8 million, depending on the timing of the next electric rate case. In addition, the lengthening of the remaining life for the Monticello nuclear plant decreased the related asset retirement obligation by $121 million in the third quarter of 2007.

NSP-Wisconsin

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**.**

On Oct. 15, 2007, the PSCW staff and intervenors filed testimony in response to NSP-Wisconsin s requested increase. The PSCW staff recommended an electric rate increase of approximately $44.1 million and a natural gas rate increase of $4.3 million, based on a return on equity of 10.75 percent and a common equity ratio of 53.58 percent. The PSCW staff testimony recommended adjustments that would decrease NSP-Wisconsin s electric request by approximately $23.3 million. Approximately half of the PSCW staff s adjustments are based on new or revised data since the filing was prepared. Specifically, PSCW staff increased 2008 forecast electric revenues based on a more recent forecast of electric sales and energy losses and also recognized the increased revenues generated by the electric fuel surcharge approved by the PSCW on Oct. 11, 2007. These adjustments, if accepted by the PSCW, are not expected to have an earnings impact on NSP-Wisconsin. The remaining adjustments, discussed in PSCW staff testimony, relate to reductions in rate base, operating and maintenance expenses and amortization expenses.

The Wisconsin Industrial Energy Group (WIEG) and the Wisconsin Paper Council (WPC) also filed testimony in opposition to the rate increase on behalf of their members. WIEG proposed an electric rate increase of approximately $40.1 million, based on a 10.0 percent return on equity and a common equity ratio of 50.93 percent. WIEG disputed certain costs related to power production that are billed to NSP-Wisconsin through the interchange agreement with NSP-Minnesota, also a wholly owned subsidiary of Xcel Energy Inc. Specifically, WIEG contends that NSP-Minnesota nuclear decommissioning costs are overstated due to planned life extension at the Monticello and Prairie Island plants. WIEG is also disputing increasing costs associated with the Nuclear Management Company. Finally, WIEG contends fuel and purchased power costs are overstated because forced outage rates assumed for certain power plants

are too high. WIEG s total proposed reduction to the electric request is approximately $27.3 million. WIEG did not specifically address the proposed natural gas increase. The WPC did not propose any specific adjustments, but generally requested the PSCW minimize the size of the rate increase in light of difficult economic conditions facing the paper industry.

Additional staff and intervenor testimony on rate design issues was filed on Oct. 22, 2007, and all rebuttal testimony is due on Oct. 29, 2007. Technical and public hearings are scheduled for Nov. 8, 2007, and Nov. 12, 2007, respectively. The PSCW is expected to act upon the request in December 2007, and new rates are expected to be implemented in early 2008.

Electric Fuel Surcharge Application On Aug. 20, 2007, NSP-Wisconsin filed an application with the PSCW requesting authorization to implement an electric fuel surcharge under the provisions of the Wisconsin fuel rules. The requested surcharge would increase electric rates by $5.9 million or 1.3 percent on an annual basis. On Oct. 11, 2007, the PSCW issued an order approving interim rates at the requested level that became effective Oct. 15, 2007. This surcharge is expected to generate an estimated $1.3 million in additional revenue for NSP-Wisconsin in 2007. Under the provisions of the Wisconsin fuel rules, any difference between interim rates and final rates is subject to refund. The PSCW is expected to review NSP-Wisconsin s actual 2007 fuel costs in the first quarter of 2008 to determine whether any refund of interim rates is necessary.

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 electric 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.

On Aug. 30, 2007, the PSCW issued its written order in this case approving 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 that MISO s subsequent billing correction related to over collected losses. These two exceptions would have reduced the June 30, 2006 deferral by $5.0 million. 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. In the order, the PSCW also included a provision that allows NSP-Wisconsin to contest a portion of the disallowance relating to transmission line losses in its current rate case.

As of Sept. 30, 2007, NSP-Wisconsin has deferred approximately $6.0 million of MISO Day 2 costs, which fully reflects the PSCW s decisions in this case.

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. Rebuttal testimony will be filed on Oct. 29, 2007 in the electric rate case, NSP-Wisconsin intends to request recovery of an additional $0.5 million of MISO Day 2 costs related to the disallowance for transmission line losses.

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.

On Aug. 24, 2007, the PSCW staff issued its draft revisions to the fuel rules and requested comments. The draft rules are based largely on the original proposal submitted by the joint utilities, but incorporate the modifications requested by the PSCW. The proposed rules incorporate a plan year fuel cost forecast, deferred accounting for differences between actual and forecast costs (if the difference is greater than 2 percent), and an after the fact reconciliation proceeding to allow the opportunity to recover or refund the deferred balance. On Sept. 11, 2007, the utilities and the customer intervenor group filed comments on the PSCW staff s proposed revisions to the rules. The utilities generally supported the draft rules but provided comments on legal issues and policy concerns surrounding the proposed rules. In their comments, the customer intervenor group asserted that the proposed rule changes are in conflict with the statutory prohibition on automatic fuel cost adjustment and constitute retroactive ratemaking.

The PSCW is expected to consider the draft rule and filed comments at an open meeting in the fourth quarter of 2007. At this time it is not certain what changes, if any, 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 assumed a common equity ratio of 60.17 percent and a ROE of 11 percent. The jurisdictional rate base is approximately $1.1 billion.

On July 3, 2007, the CPUC approved with modifications a comprehensive settlement between PSCo, the CPUC staff, the Colorado Office of Consumer Counsel (OCC) and Seminole Energy Services, LLC, providing for, among other things, the following:

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

A modification to 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 annual decline in use (to be reflective of 50 percent of the historic average annual decline in use).

Final rates were implemented effective July 30, 2007.

Transmission Cost Adjustment Rider - On Sept. 7, 2007, PSCo filed with the CPUC a request to implement a transmission cost adjustment rider, which would recover approximately $18.2 million in 2008. This filing is pursuant to recently enacted legislation which entitled public utilities to recover, through a separate rate adjustment clause, the costs that it prudently incurs in planning, developing, and completing the construction or expansion of transmission This legislation further encourages utilities to invest in transmission facilities by allowing the recovery of the total balance of construction work in progress related to those transmission investments at PSCo s weighted average cost of capital including its most recently authorized rate of ROE. The CPUC staff and certain other parties are challenging the scope of PSCo s requested cost recovery under the rider during 2008 and have asked the CPUC to set PSCo s application for hearing. The Company expects the CPUC to rule on its application prior to Dec. 31, 2007.

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 and that SPS had inappropriately allocated average fuel and purchased power costs to its other wholesale customers, effectively raising the fuel costs charges to complainants. Cap Rock Energy Corporation (Cap Rock), a 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 administrative law judge (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 served under 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 firm 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.

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. SPS has entered into settlement discussions with the wholesale cooperative customers. As of Sept. 30, 2007, based upon management s estimate of this potential liability, SPS believes the appropriate accrual has been recorded for this matter.

Additionally, SPS has entered into settlement discussions with the wholesale cooperative customers. As of Sept. 30, 2007, based upon management s estimate of this potential liability, SPS believes the appropriate accrual has been recorded for this matter.

In July and September 2007, Golden Spread and SPS filed a joint motion requesting the FERC to defer the final order while the cooperative customers negotiate the complaint case. The case is still pending final FERC action.

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. On Sept. 7, 2006, an offer of settlement with respect to the five full-requirements customers was filed for approval and on Sept. 19, 2006, the offer of settlement with respect to PNM was filed for approval. On Sept. 20, 2007, the FERC accepted the settlement with the full-requirements customers. The PNM settlement is still pending before the FERC.

Golden Spread Electric Cooperative, SPS partial requirements wholesale customer, did not settle and hearings were set for the rate disputes raised by Golden Spread. Subsequent to filing rebuttal testimony, on March 29, 2007, SPS and Golden Spread entered into additional settlement negotiations. The current hearing schedule has been postponed . The FERC has appointed a settlement judge to facilitate negotiations.

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 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 (SO_2)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, which was filed in July 2007, 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 SO_2 allowances in a separate proceeding. Although there is no deadline for NMPRC action, SPS expects the NMPRC will act during the fourth quarter of 2007. As of Sept. 30, 2007, based upon management s estimate of this potential liability, SPS believes the appropriate accrual has been recorded for this matter.

New Mexico Electric Rate Case - On July 30, 2007, SPS filed with the NMPRC requesting a New Mexico retail electric general rate increase of $17.3 million annually, or a 6.6 percent increase. The rate filing is based on a 2006 calendar year base period adjusted for known and measurable changes and includes a requested rate of return on equity of 11.0 percent, an electric rate base of approximately $307.3 million allocated to the New Mexico retail jurisdiction and an equity ratio of 51.2 percent. The NMPRC suspended the requested effective date for an additional nine months beyond the requested effective date. Intervenor testimony is due Dec. 21, 2007 and hearings are scheduled for Jan. 28-Feb. 1, 2008. A decision on the request is expected in the second quarter of 2008, and final rates are expected to be implemented in mid-2008.

Investigation of SPS Participation in SPP - On Oct. 16, 2007, the PRC issued an order initiating an investigation to consider the prudence and reasonableness of SPS participation in the Southwest Power Pool, Inc. (SPP) RTO. The investigation will consider the costs and benefits of RTO participation to SPS customers in New Mexico. The order required SPS to file direct testimony no later than 75 days after the completion of the hearing in the New Mexico electric rate case.

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 included in Xcel Energy s Current Report on Form 8-K filed on Aug. 8, 2007, 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 During the second and third quarters of 2007, PSCo commenced purchased power agreements that are being accounted for as operating leases in accordance with Emerging Issues Task Force 01-8, *Determining Whether an Arrangement Contains a Lease* and SFAS 13 *Accounting for Leases* . These agreements require capacity payments of $30.2 million, $35.7 million, $32.0 million, $21.3 million, $17.1 million and $355.6 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 Sept. 30, 2007, the liability for the cost of remediating these sites was estimated to be $28.2 million, of which $2.9 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

Insurance coverage;

Other parties that have contributed to the contamination; and

Customers.

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

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site NSP-Wisconsin was named a PRP for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (Ashland site) includes property owned by NSP-Wisconsin, which was previously an MGP facility, and two other properties: an adjacent city lakeshore park area, on which an unaffiliated third party previously operated a sawmill, and an area of Lake Superior s Chequemegon Bay adjoining the park.

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) Program accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007, and the EPA is scheduled to complete its assessment in the fourth quarter of 2007. 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. In September 2007, the EPA approved the series of reports included in the remedial investigation (RI) report. The draft feasibility study, which develops and assesses the alternatives for cleaning up the site, will be prepared by NSP-Wisconsin and is expected to be submitted to the EPA during the fourth quarter 2007.

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 are expected to 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. Estimated future project costs, based upon an assumed 30-year system operating life, including EPA oversight costs, are approximately $3.9 million.

In April 2005, PSCo brought a contribution action against Schrader 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 alleged as part of its counterclaim an imminent and substantial endangerment of its property as defined by RCRA. PSCo filed a motion for partial summary judgment to dismiss Schrader s RCRA claim. Oral argument on PSCo s motion was held Sept. 12, 2007, and on Oct. 10, 2007 the court granted PSCo s motion for partial summary judgment and dismissed Schrader s RCRA claim. Schrader also recently filed a motion for summary judgment seeking to dismiss PSCo s CERCLA claim. PSCo believes this motion is without merit and will vigorously defend its claim.

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 in the consolidated financial statements included in Xcel Energy s Current Report on Form 8-K filed on Aug. 8, 2007. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Cunningham and Maddox 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 has been finalized, but no court date has been set to hear oral arguments.

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 SO_2 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 megawatts (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 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 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. To date NSP-Minnesota has spent approximately $1.2 million on mercury monitoring implementation.

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 to defer these costs as a regulatory asset with a cap of $6.3 million. To date NSP-Minnesota has spent approximately $1.2 million on mercury monitoring implementation.

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 early 2008 for submittal to the EPA later in the year. 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 obtained public comment on its BART determination and PSCo s BART permits. A public hearing before the Air Quality Control Commission is scheduled for Dec. 20, 2007 to review and consider the approval of the BART permits for PSCo.

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. The preliminary projected cost of this project is estimated at $900 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. An updated regulatory filing detailing the proposed project is planned in the fourth quarter of 2007.

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. In June 2007, the EPA suspended the deadlines and referred any implementation to each state s best professional judgment until the EPA is able to fully respond to the court-ordered 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.

New York Office of the Attorney General Subpoena - **On Sept.14, 2007 the Office of the New York Attorney General (NYAG) issued a subpoena pursuant to the Martin Act, a New York statute, to Xcel Energy. The subpoena seeks information and documents related to Xcel Energy s analysis of risks posed by climate change and possible climate legislation and its disclosures of such risks to investors. In a letter accompanying the subpoena, the NYAG asserts that the increase in CO2 emissions upon completion of construction of Comanche 3 (a coal-fired unit), in combination with Xcel s other coal-fired plants, will subject Xcel to increased financial, regulatory and litigation risks which need to be disclosed to shareholders. Xcel Energy believes it has fully disclosed these risks, to the extent they can be ascertained, and such disclosures belie the concerns expressed by the NYAG.**

PSCo Notice of Violation 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. A motion to dismiss was filed by the defendants in September 2007.

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 Employee Retirement Income Security Act (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 the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the judge granted the 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 regarding the impact of the United States Supreme Court s decision in Massachusetts v. EPA, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in Massachusetts v. EPA, the United States Supreme Court held that CO_2 emissions are a pollutant subject to regulation by the EPA under the Clean Air Act. In response to the request of the Second Circuit Court of Appeals, 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 the utilities 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 on Sept. 24, 2007 the 9th Circuit Court of Appeals reversed the dismissal and remanded to Judge Pro for consideration of whether any of Plaintiffs claims are based on retail rates not directly barred by the filed rate doctrine.

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 on Sept. 24, 2007, the 9th Circuit Court of Appeals reversed the dismissal and remanded to Judge Pro for consideration of whether any of plaintiffs claims are based on retail rates not directly barred by the filed rate doctrine.

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 on Sept. 24, 2007, the 9th Circuit Court of Appeals reversed the dismissal and remanded to Judge Pro for consideration of whether any of plaintiffs claims are based on retail rates not directly barred by the filed rate doctrine.

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 9th Circuit Court of Appeals and on Sept. 24, 2007, the 9th Circuit Court of Appeals reversed the dismissal and remanded to Judge Pro for consideration of whether any of plaintiffs claims are based on retail rates not directly barred by the filed rate doctrine.

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 was stayed pending the Ninth Circuit s disposition of the Abelman Art Glass and Texas-Ohio appeals and will remain in effect until Oct. 26, 2007, at which time it will likely be considered by the court in light of the decision in the Abelman, Fairhaven, Utility Savings and Texas-Ohio cases.

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 was 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 and e prime s motion to dismiss the complaint was denied in July 2007, and in September 2007 both entities filed an answer to the complaint.

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 by Judge Pro in December 2006. Plaintiff subsequently filed a motion to amend the judgment and defendants filed an opposition to that motion in February 2007. In July 2007, Judge Pro reversed his dismissal of the complaint and ordered defendants to file answers. In September 2007, Xcel Energy and e prime filed their answer to the complaint.

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. 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. Defendants motion to dismiss, filed in January 2007, was denied in July 2007. Defendants answered the complaint and in September 2007 filed a motion for summary judgment. In October 2007, plaintiffs moved to amend the complaint by adding e prime Energy Marketing as a defendant.

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.

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 CAPCD alleging that the division improperly granted permits to PSCo under Colorado s Prevention of Significant Deterioration program for the construction and operation of Comanche 3. PSCo intervened in the case. 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. On Oct. 16, 2007, oral arguments were presented to the Colorado Court of Appeals, who took the matter under advisement and is expected to issue an opinion in due course.

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 final form of the settlement documents was agreed upon and the settlement documents were executed in September 2007. The court filed an order of dismissal on Oct. 15, 2007. The settlement is not expected to have a material impact on Xcel Energy s consolidated financial statements.

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 and made motions to exclude the testimony of plaintiffs experts. Both sides made motions for summary judgment, which were denied in September 2007, except that plaintiffs trespass claims were dismissed. NSP-Minnesota filed a motion to certify questions for immediate appellate review on Oct. 16, 2007, which is scheduled to be heard on Oct. 30, 2007. NSP-Minnesota has also petitioned the Minnesota Court of Appeals for permission to appeal. The 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, and oral arguments were heard Oct. 24, 2007.

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 CO_2 emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. On July 19, 2006, Xcel Energy filed a motion to dismiss the lawsuit in its entirety. On Aug. 30, 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. On Sept. 17, 2007, plaintiffs filed a notice of appeal to the Fifth Circuit.

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 reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions.

On July 6, 2007, the Minnesota trial court issued its third decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of eleven insurers whose coverage would not be triggered under such an allocation method. On Sept. 16, 2007, NSP-Wisconsin commenced an appeal in the Court of Appeals for Minnesota challenging the dismissal of these carriers.

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 consolidated financial statements.

Pacific Northwest FERC Refund Proceeding - In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been an active participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence regarding the use of certain strategies and how they may have impacted the markets in the Pacific Northwest markets. For the referenced period, parties have claimed that the total amount of transactions with PSCo subject to refund are $34 million. On June 25, 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. On Nov. 10, 2003, in response to requests for rehearing, FERC reaffirmed this ruling to terminate the proceeding without refunds. Certain purchasers filed appeals of the FERC s orders in this proceeding with the United States Court of Appeals for the Ninth Circuit.

In an order issued on Aug. 24, 2007, the Ninth Circuit issued an order remanding the proceeding back to the FERC. The court preliminarily determined that it had jurisdiction to review the FERC s decision not to order refunds. In remanding the case back to FERC, the court directed that the FERC consider evidence that had been presented regarding intentional market manipulation in the California markets and its potential ties to transactions in the Pacific Northwest. The court also indicated that the FERC should consider other of its rulings addressing overcharges in the California organized markets.

Nuclear Waste Disposal Litigation - In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the United States Department of Energy s (DOE) failure to begin disposing of spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. When the matter went to trial in October 2006, NSP-Minnesota was claiming damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. On Oct. 11, 2007 the DOE filed a motion for reconsideration in which it asks the court to reverse several of its key findings. NSP-Minnesota has been given until Nov. 13, 2007 to respond to the motion. The DOE has 60 days from Sept. 26, 2007, in which to file an appeal. Results of the judgment will not be recorded in earnings until the regulatory treatment and amounts to be shared with rate payers has been resolved. Given the uncertainty of a potential appeal and regulatory treatment by the various utility commissions, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

On Aug. 15, 2007, NSP-Minnesota filed a second complaint against the DOE in the Court of Federal Claims, again claiming breach of contract damages for the DOE s continuing failure to abide by the terms of the contract. This lawsuit claims damages for the period Jan. 1, 2005 through June 30, 2007, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. The amount of such damages is expected to exceed $40 million. The government has asked for and received an extension to file its answer, and its answer is now due Dec.14, 2007.

Mallon v. Xcel Energy Inc.

On July 6, 2007 Theodore Mallon and TransFinancial Corporation filed a declaratory judgment action against Xcel Energy in United States District Court in Colorado (Mallon Federal Action). In this lawsuit, plaintiffs seek a determination that Xcel Energy is not entitled to assert claims against plaintiffs related to the 1984 and 1985 sale of COLI to PSCo, a predecessor of Xcel Energy. On Aug. 15, 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in state court in Boulder County, Colo. against Mallon and TransFinancial Corporation (Mallon State Action). In the Mallon State Action, Xcel Energy, PSCo and PSRI, a subsidiary of PSCo seek damages against Mallon and TransFinancial for, among other things, breach of contract and breach of fiduciary duties associated with the sale of the COLI policies. On Aug. 15, 2007, Xcel Energy also filed a motion to stay or, in the alternative, to dismiss the Mallon Federal Action. A motion to stay the Mallon State Court action was subsequently filed by plaintiffs Mallon and TransFinancial on Sept. 18, 2007. The motions in both the state and federal court proceedings are still pending and it is uncertain when a decision will be issued by either court.

Other Contingencies

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 Sept. 30, 2007, Xcel Energy and its subsidiaries had approximately $420.2 million of short-term debt outstanding at a weighted average interest rate of 5.58 percent.

Guarantees

Xcel Energy provides various guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On Sept. 30, 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 Sept. 30, 2007, was approximately $31.6 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. There were no conversions during the third quarter of 2007.

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 Aug. 1, 2007, NSP-Minnesota redeemed all of its outstanding 8.00 percent Notes, Series due 2042, 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. Upon redemption, Xcel Energy recognized approximately $9.3 million in interest expense due to unwinding a fair value interest rate derivative.

On Aug. 15, 2007, PSCo issued $350 million of 6.25 percent first mortgage bonds, series due 2037. PSCo 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, including commercial paper incurred to fund the payment at maturity of $100 million of 7.11 percent secured medium-term notes, which matured on March 5, 2007.

Credit Facility Borrowings On Sept. 30, 2007, Xcel Energy and its utility subsidiaries had the following borrowings against their five-year unsecured credit facilities:

(Millions of dollars)	**Facility**	**Borrowings**
NSP-Minnesota	$ 500	$ 200
PSCo	700	
SPS	250	125
Xcel Energy Holding Company	800	150
Total	$ 2,250	$ 475

The weighted average interest rate on the borrowings was approximately 5.83 percent. The borrowings were all repaid on Oct. 1, 2007.

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 Sept. 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 recorded in Other Comprehensive Income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. This could include the purchase or sale of energy or energy-related products, the use of natural gas to generate electric energy or gas purchased for resale.

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 Sept. 30, 2007, Xcel Energy had net gains of approximately $1.1 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 third quarter of 2007.

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

(Millions of Dollars)	Three months ended Sept. 30, 2007	2006
Accumulated other comprehensive income related to cash flow hedges at July 1	$ 8.3	$ 19.5
After-tax net unrealized gains related to derivatives accounted for as hedges	(2.0)	(16.1)
After-tax net realized gains on derivative transactions reclassified into earnings	(0.2)	0.2
Accumulated other comprehensive income related to cash flow hedges at Sept. 30	$ 6.1	$ 3.6

(Millions of Dollars)	Nine months ended Sept. 30, 2007	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	4.6	12.7
After-tax net realized gains on derivative transactions reclassified into earnings	(0.7)	(0.3)
Accumulated other comprehensive income related to cash flow hedges at Sept. 30	$ 6.1	$ 3.6

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 the Consolidated Statements of Income. The results of these transactions are recorded as a component of Operating Expenses 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 nine months ended Sept. 30 consisted of the following:

	Three months ended Sept. 30,	Nine months ended Sept. 30,

(Thousands of dollars)	2007	2006	2007	2006
Interest income	$ 6,101	$ 4,158	$ 15,180	$ 13,811
Equity income in unconsolidated affiliates	616	1,192	2,800	3,470
Other nonoperating income	1,479	2,190	2,710	6,284
Minority interest income	225	1,795	472	2,098
Other nonoperating expense	(1,973)	(3,753)	(5,659)	(9,688)
Total interest and other income, net	$ 6,448	$ 5,582	$ 15,503	$ 15,975

11. Common Stock and Equivalents

Xcel Energy has common stock equivalents consisting of convertible senior notes, 401(k) equity awards and stock options. Restricted stock units and performance shares are included as common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the reporting period. For the three and nine months ended Sept. 30, 2007, Xcel Energy had approximately 9.5 million and 10.3 million options outstanding, respectively, that were antidilutive and, therefore, excluded from the dilutive earnings per share calculation. For the three and nine months ended Sept. 30, 2006, Xcel Energy had approximately 11.1 million and 12.7 million options outstanding, respectively, that were antidilutive.

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

(Amounts in thousands, except per share amounts)	Three months ended Sept. 30, 2007 Income	Shares	Per-share Amount	Three months ended Sept. 30, 2006 Income	Shares	Per-share Amount
Income from continuing operations	$ 246,345			$ 213,848		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Income from continuing operations	245,285	419,822	$ 0.58	212,788	406,123	$ 0.52
Effect of dilutive securities:						
Convertible debt	2,190	13,094		3,787	23,317	
401(k) equity awards		435			518	
Stock options		36			42	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 247,475	433,387	$ 0.57	$ 216,575	430,000	$ 0.50

(Amounts in thousands, except per share amounts)	Nine months ended Sept. 30, 2007 Income	Shares	Per-share Amount	Nine months ended Sept. 30, 2006 Income	Shares	Per-share Amount
Income from continuing operations	$ 484,628			$ 455,057		
Less: Dividend requirements on preferred stock	(3,180)			(3,180)		
Basic earnings per share:						
Income from continuing operations	481,448	413,555	$ 1.16	451,877	405,234	$ 1.12
Effect of dilutive securities:						
Convertible debt	8,975	18,726		11,308	23,317	
401(k) equity awards		441			517	
Stock options		89			27	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 490,423	432,811	$ 1.13	$ 463,185	429,095	$ 1.08

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three months ended Sept. 30,			
	2007 (1)	2006	2007	2006
(Thousands of dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 15,520	$ 15,406	$ 1,453	$ 1,659
Interest cost	41,313	38,854	12,619	13,234
Expected return on plan assets	(66,208)	(67,017)	(7,600)	(6,690)
Amortization of transition obligation			3,644	3,611
Amortization of prior service cost (credit)	6,487	7,424	(545)	(544)
Amortization of net loss	4,211	4,339	3,550	6,200
Net periodic benefit cost (credit)	1,323	(994)	13,121	17,470
Credits not recognized due to the effects of regulation	2,787	3,159		
Additional cost recognized due to the effects of regulation			972	972

Net benefit cost recognized for financial reporting	$	4,110	$	2,165	$	14,093	$	18,442

	Nine months ended Sept. 30, 2007 (1)	2006	2007	2006
(Thousands of dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 46,560	$ 46,220	$ 4,359	$ 4,975
Interest cost	123,939	116,560	37,857	39,704
Expected return on plan assets	(198,624)	(201,049)	(22,800)	(20,068)
Amortization of transition obligation			10,932	10,833
Amortization of prior service cost (credit)	19,461	22,272	(1,635)	(1,634)
Amortization of net loss	12,633	13,015	10,650	18,598
Net periodic benefit cost (credit)	3,969	(2,982)	39,363	52,408
Credits not recognized due to the effects of regulation	8,361	9,477		
Additional cost recognized due to the effects of regulation			2,918	2,918
Net benefit cost recognized for financial reporting	$ 12,330	$ 6,495	$ 42,281	$ 55,326

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

13. Segment Information

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

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Three months ended Sept. 30, 2007					
Operating revenues from external customers	$ 2,199,533	$ 184,161	$ 16,303	$	$ 2,399,997
Intersegment revenues	193	4,057		(4,250)	
Total revenues	$ 2,199,726	$ 188,218	$ 16,303	$ (4,250)	$ 2,399,997
Income (loss) from continuing operations	$ 260,441	$ 1,388	$ 800	$ (16,284)	$ 246,345
Three months ended Sept. 30, 2006					
Operating revenues from external customers	$ 2,159,844	$ 230,293	$ 21,454	$	$ 2,411,591
Intersegment revenues	180	5,676		(5,856)	
Total revenues	$ 2,160,024	$ 235,969	$ 21,454	$ (5,856)	$ 2,411,591
Income (loss) from continuing operations	$ 223,368	$ (211)	$ (3,755)	$ (5,554)	$ 213,848

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Nine months ended Sept. 30, 2007					
Operating revenues from external customers	$ 5,935,031	$ 1,442,451	$ 53,469	$	$ 7,430,951
Intersegment revenues	708	14,225		(14,933)	
Total revenues	$ 5,935,739	$ 1,456,676	$ 53,469	$ (14,933)	$ 7,430,951
Income (loss) from continuing operations	$ 456,405	$ 67,220	$ 10,059	$ (49,056)	$ 484,628
Nine months ended Sept. 30, 2006					
Operating revenues from external customers	$ 5,792,287	$ 1,519,423	$ 61,858	$	$ 7,373,568
Intersegment revenues	567	9,443		(10,010)	

Total revenues	$	5,792,854	$	1,528,866	$	61,858	$	(10,010)	$	7,373,568
Income (loss) from continuing operations	$	427,102	$	47,963	$	18,423	$	(38,431)	$	455,057

14. Nuclear Management Company

On Sept. 28, 2007, Xcel Energy obtained 100 percent ownership in Nuclear Management Company (NMC) as a result of Wisconsin Energy Corporation (WEC) exiting the partnership due to the sale of its Point Beach Nuclear Plant to FPL Energy. Accordingly, the results of operations of NMC and the estimated fair value of assets and liabilities were consolidated in Xcel Energy s consolidated financial statements from the Sept. 28, 2007, transaction date. WEC was required to pay an exit fee and surrender all of its equity interest in NMC upon exiting. The effect of this transaction was not material to the financial position or the results of operations to Xcel Energy for the three and nine months ended Sept. 30, 2007 and 2006. Xcel Energy plans to reintegrate its nuclear operations into its generation operations and apply to the Nuclear Regulatory Commission to transfer the nuclear operating licenses from NMC to NSP-Minnesota. The transfer of licenses is expected to be completed in early 2008.

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

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

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate, believe, estimate, expect, intend, may, objective, outlook, plan, project, possible, pote expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A of Xcel Energy s Form 10-K for the year ended Dec. 31, 2006 and Exhibit 99.01 to this report on Form 10-Q for the quarter ended Sept. 30, 2007.

RESULTS OF OPERATIONS

Summary of Financial Results

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

- regulated utility subsidiaries, operating in the electric and natural gas segments; and
- 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 management s decision to surrender all COLI policies in connection with a settlement with the IRS.

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

Contribution to Earnings (Millions of dollars)	**Three months ended Sept. 30, 2007**	**2006**	**Nine months ended Sept. 30, 2007**	**2006**
Regulated electric utility segment income continuing operations	$ 260.4	$ 223.4	$ 456.4	$ 427.1
Regulated natural gas utility segment income continuing operations	1.4	(0.2)	67.2	48.0
Other utility results (a)	(1.7)	(5.9)	6.6	(0.4)
Utility segment income continuing operations	260.1	217.3	530.2	474.7
Holding company and other results	(13.8)	(3.4)	(45.6)	(19.6)
Income continuing operations	246.3	213.9	484.6	455.1
Regulated utility income discontinued operations	0.1	1.1	0.1	2.2
Other nonregulated income discontinued operations	5.3	9.5	(37.3)	16.7
Income discontinued operations	5.4	10.6	(37.2)	18.9
Net income	$ 251.7	$ 224.5	$ 447.4	$ 474.0

	Three months ended Sept. 30, 2007	Three months ended Sept. 30, 2006	Nine months ended Sept. 30, 2007	Nine months ended Sept. 30, 2006
Regulated electric utility segment continuing operations	$ 0.60	$ 0.52	$ 1.05	$ 1.00
Regulated natural gas utility segment continuing operations			0.16	0.11
Other utility results (a)		(0.02)	0.01	
Utility segment earnings per share continuing operations	0.60	0.50	1.22	1.11
Holding company and other results	(0.03)		(0.09)	(0.03)
Earnings per share continuing operations	0.57	0.50	1.13	1.08
Regulated utility earnings discontinued operations				
Other nonregulated earnings discontinued operations	0.01	0.03	(0.08)	0.04
Earnings per share discontinued operations	0.01	0.03	(0.08)	0.04
Total earnings per share - diluted	$ 0.58	$ 0.53	$ 1.05	$ 1.12

(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 nine months ended Sept. 30, 2007, earnings per share compared with the same period in 2006, which are discussed in more detail later.

Increase (decrease)	**Three months ended Sept. 30, 2007 vs. 2006**	**Nine months ended Sept. 30, 2007 vs. 2006**
2006 Earnings per share	**$ 0.53**	**$ 1.12**
Components of change 2007 vs. 2006		
Higher base electric utility margins	0.15	0.21
Lower short-term wholesale and commodity trading margins	(0.01)	(0.01)
Higher natural gas margins		0.04
Higher utility operating and maintenance expense	(0.05)	(0.07)
Lower (higher) depreciation and amortization expense	0.02	(0.01)
Higher financing costs	(0.02)	(0.04)
Higher effective tax rate	(0.04)	(0.08)
Other	0.02	0.01
Net change in earnings per share continuing operations	**0.07**	**0.05**
Changes in Earnings Per Share Discontinued Operations	(0.02)	(0.12)
2007 Earnings per share	**$ 0.58**	**$ 1.05**

Utility Segment Results

Utility earnings from continuing operations for the third quarter of 2007 increased approximately $43 million during the third quarter of 2007 and increased $56 million for the first nine months of 2007, when compared to the same periods in 2006. The increase is represented by higher electric margin, reflecting the positive impact of the January 2007 Colorado rate increase, improved rider recovery for the Metro Emission Reduction Project (MERP) in Minnesota and sales growth.

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 Sept. 30,			Nine months ended Sept. 30,		
	2007 vs. Normal	2006 vs. Normal	2007 vs. 2006	2007 vs. Normal	2006 vs. Normal	2007 vs. 2006
Retail electric	$ 0.04	$ 0.03	$ 0.01	$ 0.06	$ 0.05	$ 0.01
Firm natural gas		0.01	(0.01)		(0.02)	0.02
Total	$ 0.04	$ 0.04	$	$ 0.06	$ 0.03	$ 0.03

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

PSRI PSRI, a wholly owned subsidiary of 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 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 had 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.

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

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

Income Statement Analysis Third Quarter 2007 vs. Third 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 Sept. 30, 2007				
Electric utility revenues (excluding commodity trading)	$ 2,129	$ 69	$	$ 2,198
Electric fuel and purchased power	(1,041)	(61)		(1,102)
Commodity trading revenues			74	74

Commodity trading costs						(72)		(72)
Gross margin before operating expenses	$	1,088	$	8	$	2	$	1,098
Margin as a percentage of revenues		51.1%		11.6%		2.7%		48.3%
Three months ended Sept. 30, 2006								
Electric utility revenues (excluding commodity trading)	$	2,089	$	63	$		$	2,152
Electric fuel and purchased power		(1,106)		(55)				(1,161)
Commodity trading revenues						185		185
Commodity trading costs						(177)		(177)
Gross margin before operating expenses	$	983	$	8	$	8	$	999
Margin as a percentage of revenues		47.1%		12.7%		4.3%		42.7%

Short-term wholesale and commodity trading margins decreased approximately $6 million during the third quarter of 2007, when compared to the same period in 2006. As expected, short-term wholesale margins declined due to retail sales growth, which reduced generation available for sale in the wholesale market.

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

Base Electric Utility Revenue

(Millions of dollars)	**2007 vs. 2006**
Fuel and purchased power cost recovery	$ (68)
PSCo electric retail rate increase	31
Retail sales growth (excluding weather impact)	16
Sales mix/pricing	14
Firm wholesale	14
Conservation and non-fuel riders	11
MERP rider	8
Transmission revenue	3
Estimated impact of weather	7
SPS potential regulatory settlements	(1)
Other	5
Total increase in base electric utility revenues	$ 40

Base Electric Utility Margin

(Millions of dollars)		**2007 vs. 2006**
PSCo electric retail rate increase	$	31
Retail Sales growth (excluding weather impact)		16
Firm wholesale		12
Conservation and non-fuel riders (offset in O&M expenses)		11
Transmission fee classification change (offset in O&M expenses)		11
MERP rider		8
Estimated impact of weather		7
NSP-Wisconsin fuel cost recovery		2
SPS potential regulatory settlements		(1)
Other, including sales mix, other fuel recovery and purchased capacity costs		8
Total increase in base electric utility margin	$	105

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.

	Three months ended Sept. 30,			
(Millions of dollars)	**2007**		**2006**	
Natural gas utility revenue	$	184	$	230
Cost of natural gas sold and transported		(89)		(137)
Natural gas utility margin	$	95	$	93

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

Natural Gas Revenue

(Millions of dollars)		**2007 vs. 2006**
Purchased gas adjustment clause recovery	$	(46)
Base rate changes Minnesota, North Dakota, Colorado		4
Estimated impact of weather		(3)
Sales decline (excluding weather impact)		(3)
Other		2
Total decrease in natural gas revenues	$	(46)

Natural Gas Margin

(Millions of dollars)		**2007 vs. 2006**
Base rate changes Minnesota, North Dakota, Colorado	$	3
Sales decline (excluding weather impact)		(3)
Service and facility fees revenue		2
Transportation		2
Estimated impact of weather		(1)
Other, including late payment fees and other miscellaneous revenue		(1)
Total increase in natural gas margin	$	2

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses Utility Other operating and maintenance expenses for the third quarter of 2007 decreased by approximately $34 million, or 8.2 percent, compared with the same period in 2006. For more information see the following table:

(Millions of Dollars)		**Three months ended Sept. 30, 2007 vs. 2006**
Higher conservation incentive programs (offset in electric margins)	$	13
Transmission fees classification change (offset in electric margins)		11
Higher uncollectible receivable costs		7
Higher combustion/hydro plant costs		4
Lower employee benefit costs		(3)
Lower consulting costs		(2)
Higher nuclear plant operation costs		2
Higher donation costs		2
Total increase in other operating and maintenance expense-utility	$	34

The transmission fee classification change was the result of a year-to-date reclass of transmission expense in September 2006 from other operating and maintenance expenses-utility to electric utility margin, with no impact on operating income or net income.

Depreciation and Amortization Depreciation and amortization expense decreased by approximately $17 million, or 8.1 percent, for the third quarter of 2007, compared with the third quarter of 2006. The decrease was primarily due to the MPUC approval of NSP-Minnesota s remaining lives depreciation filing lengthening the life of the Monticello nuclear plant by 20 years, effective as of Jan. 1, 2007, as well as certain other smaller plant life adjustments. The adjustments from this order resulted in an approximate $31 million reduction of depreciation expense in the third quarter. The completion of the upgrade to the King plant, which came on-line in July 2007, increased depreciation expense this quarter by $3.5 million. These two events, when combined with the normal increase in depreciation expense from increased capital expenditures for planned system expansion, resulted in the net $17 million decrease for the quarter.

Allowance for funds used during construction, equity and debt (AFDC) AFDC increased by approximately $0.8 million, or 5.0 percent, for the third quarter of 2007 when compared with the same period in 2006. The increase was due primarily to the construction of Comanche 3. The increase was partially offset by the current recovery from customers of the financing costs related to this construction through base rates, resulting in a lower recognition of AFDC.

Interest and Financing Costs Interest charges increased by approximately $16 million, or 12.9 percent, for the third quarter of 2007, compared with the third quarter of 2006. The increase is due to higher levels of both short-term and long-term debt, higher short-term interest rates and a $9.3 million interest expense due to unwinding a fair value interest rate derivative.

Income taxes Income taxes for continuing operations increased by $38 million for the third quarter of 2007, compared with the same period in 2006. The increase in income tax expense was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 35.6 percent for the third quarter of 2007, compared with 31.4 percent for the same period in 2006. The lower effective tax rate for the third quarter of 2006 was primarily due to tax benefits of $10 million associated with the reversal of a regulatory reserve related to income taxes in the third quarter of 2006. Excluding this benefit, the effective tax rate for the third quarter of 2006 would have been 34.6 percent.

Income Statement Analysis First Nine Months of 2007 vs. First Nine 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
Nine months ended Sept. 30, 2007				
Electric utility revenues (excluding commodity trading)	$ 5,745	$ 184	$	$ 5,929
Electric fuel and purchased power	(2,946)	(167)		(3,113)
Commodity trading revenues			227	227
Commodity trading costs			(221)	(221)
Gross margin before operating expenses	$ 2,799	$ 17	$ 6	$ 2,822
Margin as a percentage of revenues	48.7%	9.2%	2.6%	45.8%
Nine months ended Sept. 30, 2006				
Electric utility revenues (excluding commodity trading)	$ 5,644	$ 134	$	$ 5,778
Electric fuel and purchased power	(2,989)	(118)		(3,107)
Commodity trading revenues			520	520
Commodity trading costs			(506)	(506)
Gross margin before operating expenses	$ 2,655	$ 16	$ 14	$ 2,685
Margin as a percentage of revenues	47.0%	11.9%	2.7%	42.6%

Short-term wholesale and commodity trading margins decreased approximately $7 million for the first nine months of 2007, when compared to the same period in 2006. As expected, short-term wholesale margins declined due to retail sales growth, which reduced generation available for sale in the wholesale market.

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the nine months ended Sept. 30:

Base Electric Utility Revenues

(Millions of dollars)	2007 vs. 2006
Fuel and purchased power cost recovery	$ (116)
PSCo electric retail rate increase	85
Retail sales growth (excluding weather impact)	42
Transmission revenue	26
MERP rider	22

Conservation and non-fuel riders		20
Firm wholesale		18
SPS potential regulatory settlements		(14)
Estimated impact of weather		9
Sales mix/pricing		3
Other		6
Total increase in base electric utility revenues	$	101

Base Electric Utility Margin

(Millions of dollars)	2007 vs. 2006
PSCo electric retail rate increase	$ 85
Retail sales growth (excluding weather impact)	41
MERP rider	22
Conservation and non-fuel riders (offset in O&M expenses)	20
NSP-Wisconsin fuel cost recovery	(14)
SPS potential regulatory settlements	(14)
Firm wholesale	10
Estimated impact of weather	9
Other, including sales mix, other fuel recovery and purchased capacity costs	(15)
Total increase in base electric utility margin	$ 144

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.

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	2007	2006
Natural gas utility revenue	$ 1,442	$ 1,519
Cost of natural gas sold and transported	(1,050)	(1,156)
Natural gas utility margin	$ 392	$ 363

The following summarizes the components of the changes in natural gas revenue and margin for the nine months ended Sept. 30:

Natural Gas Revenues

(Millions of dollars)	2007 vs. 2006
Purchased gas adjustment clause recovery	$ (126)
Estimated impact of weather	30
Base rate changes Minnesota, North Dakota, Colorado	13
Transportation	4
Sales decline (excluding weather impact)	(1)
Other	3
Total decrease in natural gas revenues	$ (77)

Natural Gas Margin

(Millions of dollars)	**2007 vs. 2006**
Estimated impact of weather	$ 12
Base rate changes Minnesota, North Dakota, Colorado	11
Service and facility fees revenue	7
Transportation	4
Other, including late payment fees	(5)
Total increase in natural gas margin	$ 29

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses Utility Other operating and maintenance expenses for the first nine months of 2007 increased $53 million, or 4.1 percent, compared with the same period in 2006. For more information see the following table:

(Millions of Dollars)		**Nine months ended Sept, 30, 2007 vs. 2006**
Higher combustion/hydro plant costs	$	18
Lower employee benefit costs		(14)
Higher nuclear plant operation costs		10
Higher conservation incentive programs (offset in electric margins)		9
Higher uncollectible receivable costs		9
Higher donation costs		7
Higher consulting costs		5
Higher nuclear plant outage costs		4
Other		5
Total increase in other operating and maintenance expense-utility	$	53

Lower year-to-date performance based incentive plan expense as well as active and retiree healthcare expense due in part to lower claims experience were the primary factor contributing to the lower employee benefit costs.

Depreciation and Amortization Depreciation and amortization expense increased by approximately $5 million, or 0.8 percent, for the first nine months of 2007, compared with the same period in 2006. Depreciation and amortization expense typically increases three to five percent year over year because of increased property, plant and equipment expenditures. This smaller increase for the first nine months of 2007 was primarily due to the MPUC approval of NSP-Minnesota s remaining lives depreciation filing lengthening the life of the Monticello nuclear plant by 20 years, effective as of Jan. 1, 2007, as well as certain other smaller plant life adjustments. The adjustments from this order resulted in an approximate $31 million reduction of depreciation expense. The completion of the upgrade to the King plant, which came on line in July 2007, increased depreciation expense by $3.5 million. These two events, when combined with the normal increase in depreciation expense from increased capital expenditures for planned system expansion, resulted in the net $5 million increase for the year.

AFDC AFDC increased by approximately $10 million, or 26.7 percent, for the first nine 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.

Interest and Financing Costs Interest charges increased by approximately $30 million, or 8.4 percent, for the first nine months of 2007, compared with the same period in 2006. The increase is due to higher levels of both short-term and long-term debt, higher short-term interest rates and a $9.3 million interest expense due to unwinding a fair value interest rate derivative.

Income taxes Income taxes for continuing operations increased by $65 million for the first nine months of 2007, compared with 2006. The increase in income tax expense was due to an increase in pretax income in 2007 and $27 million of tax benefits from the reversal of a regulatory reserve and realized capital loss carryforwards in 2006. The effective tax rate for continuing operations was 34.5 percent for the first nine months of 2007, compared with 29.5 percent for the same period in 2006. The lower effective tax rate for the first nine months of 2006 was primarily due to the recognition of a tax benefit relating to the reversal of a regulatory reserve and realized capital loss carryforwards in 2006. Excluding these benefits, the effective tax rate for the first nine months of 2006 would have been 33.7 percent.

Factors Affecting Results of Continuing Operations

Cabin Creek Hydro Generating Station

On Oct. 2, 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by Xcel Energy, were applying an epoxy coating to the inside of a penstock at Xcel Energy s Cabin Creek Hydro Generating Station near Georgetown, Colo. This work was being performed as part of a corrosion prevention maintenance effort. At approximately 2:00 p.m. a fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and confirmed their deaths. The accident is being investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA), U.S. Chemical Safety Board and the Colorado Bureau of Investigations. It is uncertain when the agencies will conclude their investigations, but it is possible these investigations could take several weeks or even months. Once OSHA s investigation is completed, we will assess the damage to the penstock and make a determination as to the steps that need to be taken in order to place this facility back in service.

Fuel Supply and Costs

See the discussion of fuel supply and costs at Factors Affecting Results of Continuing Operations in Xcel Energy s Current Report on Form 8-K filed on Aug. 8, 2007.

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.

The electric production and transmission system of NSP-Minnesota is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System. On Sept. 18, 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection, as a result of a series of transmission line outages. The initial transmission line outage appears to have occurred on the NSP-Minnesota transmission system due to a failure of a 345 KV conductor during severe weather, and approximately 6,000 NSP-Wisconsin customers temporarily lost power. The Midwest Reliability Organization (MRO), the NERC regional entity responsible for oversight of electric system reliability in the upper Midwest including the NSP System, has initiated an independent incident analysis.

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 RTO. NSP-Minnesota and NSP-Wisconsin are members of the MISO. SPS is a member of the 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 and Sept. 11, 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 allow RTO s to operate centralized regional wholesale energy markets. The FERC approved 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 response and contingency reserve services through a bid-based market mechanism co-optimized with the Day 2 energy market . In addition, MISO would consolidate the operation of approximately 20 existing 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 s 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 proposal as incomplete, as recommended by Xcel Energy. The FERC stated the ASM could still be implemented in 2008.

On Sept. 14, 2007, MISO again filed for FERC approval to establish a regional ASM whereby MISO would provide bid-based regulation response and contingency reserve markets co-optimized with the Day 2 energy market and provide for the consolidation of balancing authorities. The revised ASM is now proposed to be effective in June 2008. Xcel Energy generally supports implementation of the ASM, because it is expected to allow native NSP System generation to be used more efficiently, because certain generation will not always need to be held in reserve, and the ASM is expected to facilitate the operation of intermittent wind generation on the NSP System required to achieve state-mandated renewable energy supply standards. Comments on the ASM proposal were filed on Oct. 15, 2007. The proposal is pending FERC action.

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.

The MPUC issued its order on Aug. 30, 2007. In it, the MPUC found that:

Excelsior Energy is an innovative energy project under the applicable statute,

The terms and conditions of the proposed PPA are inconsistent with the public interest and are denied,

Excelsior Energy and NSP-Minnesota should resume negotiations towards an acceptable PPA, with assistance from the Minnesota Department of Commerce and the guidance provided by the order, and

The MPUC will explore a state-wide market for the output of this project.

Both NSP-Minnesota and Excelsior Energy filed timely requests for rehearing or clarification of this decision, which are pending before the MPUC. MPUC action is scheduled for Nov. 1, 2007.

Meanwhile, the ALJ issued a decision in Phase 2 of this proceeding, recommending denial of Excelsior s proposed PPA for a second IGCC project. Exceptions and replies have been filed. The MPUC is expected to take up this matter before year-end.

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

In September 2007, the MPUC approved NSP-Minnesota s Notice of Changed Circumstance and required the Company to file a new Resource Plan by Dec. 14, 2007. Following review of the filing and expiration of the notice and comment period, the MPUC is expected to take up matter of schedule for the base load proceeding.

Additional Base Load Capacity Projects for Sherco, Monticello and Prairie Island NSP-Minnesota had 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 its analysis of the impact of the Renewable Energy Standards and conservation goals on its need for additional resources. In September 2007, the Commission approved the Notice of Changed Circumstance and directed NSP-Minnesota to file a new Resource Plan by Dec. 14, 2007. NSP-Minnesota would file applications for appropriate certificates of needs for these projects, if confirmed by the Resource Plan, in a timely manner with or around the time of the Resource Plan to allow for consideration of the proposals using consistent data and assumptions.

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 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. NSP-Minnesota now expects to complete the transmission construction in 2008 at a cost of approximately $230 million.

In late 2006, NSP-Minnesota filed applications for certificates of need with the MPUC for three additional transmission lines in southwestern Minnesota and one in Chisago County, Minnesota. On Sept. 17, 2007, the MPUC issued a certificate of need authorizing NSP-Minnesota to construct three new 115 KV transmission lines (totaling 35 to 50 miles) in southwestern Minnesota to provide approximately 400 MW of incremental transmission delivery capacity for wind generation. The three projects, including associated substations, are expected to cost $72.5 million. The MPUC order required NSP-Minnesota to file required route permit applications by January 2008 and complete construction by Spring 2009. Evidentiary hearings regarding the Chisago County, Minnesota project were held in September 2007. The MPUC is expected to rule on the Chisago County project by late 2007 or early 2008. The project would be placed in service in 2010.

In addition, NSP-Minnesota and Great River Energy, on behalf of nine other regional transmission providers, filed a certificate of need application on Aug. 17, 2007, for three 345 KV transmission lines serving Minnesota and parts of surrounding states. As stated in the application, the three lines would include construction of approximately 700 miles of new facilities at a cost of $1.4 to $1.7 billion, with construction to be completed in phases between 2011 and 2015. The application put forth a potential ownership percentage of 36 to 72 percent for each of the three 345 KV projects for NSP-Minnesota and NSP-Wisconsin (combined). The certificate of need application for a fourth (230 KV) project is expected to be filed by year end 2007. Updated NSP-Minnesota and NSP-Winconsin cost estimates are expected following the negotiation of Project Agreements outlining the terms and conditions related to construction management, ownership, operations and maintenance of these facilities.

FCA Investigation In 2003, the MPUC opened an investigation to consider the continuing usefulness of the FCAs for electric utilities in Minnesota. There was no further activity until the MPUC issued a notice for comments on April 5, 2007, as to whether 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 MDOC filed comments seeking to continue the investigations. In response, the utilities filed additional comments on Sept. 28, 2007 that indicated a willingness to continue with the investigation and provide more information to both regulators and customers regarding fuel and purchased power costs, plant outages, and other factors affecting fuel clause levels. Reply comments are due in October 2007. The MPUC is then expected to decide whether to continue or close the 2003 investigation.

Grand Meadow Wind Farm In June 2007, NSP-Minnesota filed an application for a certificate of need for the Grand Meadows wind farm, a 100-MW development to be located in southeast Minnesota. NSP-Minnesota began developing this project pursuant to legislation adopted by the 2003 Minnesota legislature that provided the company the right to own 100 MWs of the 300 additional MWs of wind mandates required as part of its consideration of life extension at the Prairie Island nuclear plant. The Grand Meadows project would be implemented under a build-own-transfer agreement between NSP-Minnesota and enXco, a wind project developer. Total project costs are estimated to be approximately $200 million. In October 2007, the MDOC recommended approval of the certificate of need; no other public comments were received on the application. The MPUC is expected to take up this matter later this year. The application for a site permit, filed by enXco, is still pending review by the MDOC and approval by the MPUC. If approved, construction is expected to start in early 2008.

Capital Structure Petition - NSP-Minnesota filed its regular annual capital structure petition with the MPUC on Oct. 16, 2007. NSP-Minnesota is requesting an order by Dec. 31, 2007, which will approve the request for ongoing security issuance and increased capitalization. Although NSP-Minnesota may exceed its authorized capitalization in January 2008, NSP-Minnesota has a 60 day contingency period to be outside of the current authorized parameters. See a discussion of the long-term borrowings at Note 8 to the consolidated financial statements.

Other Regulatory Matters PSCo

Renewable Energy Standard - The 2007 Colorado legislature adopted an increased RES that requires PSCo to generate or cause to be generated electricity from renewable resources equaling at least 10 percent of its retail sales by 2010, 15 percent of retail sales by 2015 and 20 percent of retail sales by 2020. The new law limits the incremental retail rate impact from these acquisitions to 2 percent. The new legislation encourages the CPUC to consider earlier and timely cost recovery for utility investment in renewable resources, including the use of a 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, development and construction or expansion of transmission facilities and for current recovery through this rider of the utility s 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 . 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 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 2016. PSCo explained this capacity swap would save PSCo an estimated $49 million on a net present value basis. PSCo still planned to enter into contract extensions with three existing gas-fired facilities and to 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 intervenor, but was supported by the Colorado Office of Consumer Counsel. The opponents asked for all 2013 resource acquisition decisions to be deferred to the 2007 LCP. On Sept. 7, 2007, the CPUC issued an order approving the PSCo 2013 contingency plan and ruling that the amendments to the Tri-State agreements were exempt from the resource planning rules and need not be included in an approved contingency plan. PSCo has entered into the contract amendments with Tri-State and one of the winning gas bidders and is currently in negotiation with one otherwinning gas bidder. The third winning gas bidder has withdrawn its extension offer. The remaining 2013 resource need will be addressed in the PSCo 2007 Resource Plan.

On July 3, 2007, the CPUC issued an order soliciting comments to determine whether the LCP rules needed to be changed on an emergency basis to govern utility filings in October 2007. On Sept. 28, 2007, the CPUC adopted emergency rule changes to govern PSCo s resource plan filing in October 2007. The rule changes include: altering the requirements for least cost resource procurement and fuel neutrality to allow for selection of more renewable resources and demand-side management resources; requiring utilities to file at least three alternative plans with different levels of renewable resources and demand-side management resources so that the costs and benefits of various levels of these resources can be considered; and employing an independent evaluator to assist the CPUC in reviewing the utility s evaluation of competitive bids for resource additions. PSCo requested an extension to make its resource filing on Nov.16, 2007. On Oct. 24, 2007, the CPUC acted to grant this request.

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 20 percent by 2020. The legislation also allows performance-based incentives to encourage the acquisition of renewable energy supplies beyond the requirements. The NMPRC has implemented revised rules related to the increased requirements. The NMPRC has interpreted the diversification requirement to mean no less than 20 percent of the standard is met using wind energy, no less than 20 percent using central solar, no less than 10 percent other (e.g., biomass, geothermal), and no less than 1.5 percent using renewable distributed generation (increasing to 3 percent by 2015). The effective date of the diversification requirements is 2011.

Texas Renewable Energy Zone**s** - The PUCT designated competitive renewable energy zones (CREZs) 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. Several CREZ areas within the SPS service region were designated for potential development. The PUCT considered 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 regarding COLI

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 Current Report on Form 8-K filed Aug. 8, 2007, 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 Current Report on Form 8-K filed Aug. 8, 2007. Commodity price risks for Xcel Energy s regulated subsidiaries are mitigated in most jurisdictions due to cost-based rate regulation. At Sept. 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 Sept. 30, 2007, the VaRs for the commodity trading operations were:

(Millions of Dollars)	Period Ended Sept. 30, 2007	Change from Period Ended June 30, 2007	VaR Limit	Average	High	Low
Commodity Trading (1)	$ 0.51	$ 0.13	$ 5.00	$ 0.30	$ 0.65	$ 0.16

(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 Sept. 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 nine months ended Sept. 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):

	Nine months ended Sept. 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	(8.4)	(8.5)
Fair value of trading contract additions and changes during the period	15.9	16.9
Fair value of contracts outstanding at Sept. 30	$ 6.3	$ 12.3

As of Sept. 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	$ (14,078)	$	$	$	$ (14,078)
	2	16,070	1,144	101		17,315
PSCo	1	(1,157)				(1,157)
	2	3,231	1,145			4,376
SPS*	1	176				176
	2	237	25	1		263
Total Futures/Forwards Fair Value		$ 4,479	$ 2,314	$ 102	$	$ 6,895

(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	$ (649)	$	$	$	$ (649)
SPS*	2	8				8
Total Options Fair Value		$ (641)	$	$	$	$ (641)

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	$	$	$	$	$
	2	16,131				16,131
PSCo	1					
PSCo	2	(8,590)				(8,590)
NSP-Wisconsin	2	(585)				(585)
Total Futures/Forwards Fair Value		$ 6,956	$	$	$	$ 6,956

(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	$ 4,842	$	$	$	$ 4,842
PSCo	2	7,028	1,025			8,053
NSP-Wisconsin	2	1,060				1,060
Total Options Fair Value		$ 12,930	$ 1,025	$	$	$ 13,955

---

(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 Sept. 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 $0.1 million, whereas a 10-percent decrease would increase pretax income from continuing operations by approximately $0.1 million.

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 Sept. 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 $9.7 million annually, or approximately $2.4 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 Sept. 30, 2007, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $18.3 million, while a decrease of 10-percent would have resulted in a decrease of $10.9 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	**Nine months ended Sept. 30, 2007**	**2006**
Cash provided by operating activities		
Continuing operations	$ 1,320	$ 1,444
Discontinued operations	84	152
Total	$ 1,404	$ 1,596

Cash provided by operating activities for continuing operations decreased by $124 million for the first nine months of 2007, compared with the first nine months of 2006. This decrease was largely due to the timing of working capital activity. Specifically, the collection of receivables and the billing of accrued revenues.

(Millions of Dollars)	**Nine months ended Sept. 30, 2007**	**2006**
Cash provided by (used in) investing activities		
Continuing operations	$ (1,453)	$ (1,153)
Discontinued operations		42
Total	$ (1,453)	$ (1,111)

Cash used in investing activities for continuing operations increased by $300 million for the first nine months of 2007, compared with the first nine months of 2006. The increase was primarily due to increased capital expenditures. The increase in capital expenditures was partially offset by the cash obtained from consolidation of NMC.

(Millions of Dollars)	Nine months ended Sept. 30, 2007	2006
Cash provided by (used in) financing activities		
Continuing operations	$ 389	$ (547)
Discontinued operations		
Total	$ 389	$ (547)

Cash provided by financing activities for continuing operations increased by $936 million for the first nine months of 2007, compared with the first nine months of 2006. The increase was largely due to increased short- and long-term debt in the first nine months of 2007 compared to first nine months of 2006.

Capital Sources

Xcel Energy and Utility Subsidiary Credit Facilities - As of Oct. 22, 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	$ 306.5	$ 193.5	$ 1.2	$ 194.7	December 2011
PSCo	700	5.4	694.6	0.7	695.3	December 2011
SPS	250	120.0	130.0	0.4	130.4	December 2011
Xcel Energy Holding Company	800	294.0	506.0	2.4	508.4	December 2011
Total	$ 2,250	$ 725.9	$ 1,524.1	$ 4.7	$ 1,528.8	

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

The liquidity table reflects the payment of common dividends on Oct. 22, 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 Oct. 22, 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 Sept. 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 Sept. 30, 2007, was $420.2 million at a weighted average yield of 5.58 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 Sept. 30, 2007, and the short-term borrowing limits from the money pool are as follows:

	Borrowings (Loans)	Total Borrowing Limits
NSP-Minnesota	$	$ 250 million
PSCo		250 million
SPS		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 - NSP-Minnesota filed its regular annual capital structure petition with the MPUC on Oct. 16, 2007. NSP-Minnesota is requesting an order by Dec. 31, 2007, which will approve the request for ongoing security issuance and increased capitalization. Although NSP-Minnesota may exceed its authorized capitalization in January 2008, NSP-Minnesota has a 60 day contingency period to be outside of the current authorized parameters. See a discussion of the long-term borrowings at Note 8 to the consolidated financial statements.

Future Financing Plans

During the fourth quarter of 2007, Xcel Energy anticipates issuing approximately $400 - $500 million of hybrid securities to fund utility equity investments and for general corporate purposes.

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	$1.51 - $1.55
Holding company financing costs and other	(0.13)
Xcel Energy Continuing Operations	**$1.38 - $1.42**
Total Discontinued Operations	**$(0.07)**
Total Xcel Energy	**$1.31-$1.35**

Key Assumptions for 2007:

Normal weather patterns are experienced during the year.

No material incremental accruals related to the SPS regulatory proceedings.

Weather-adjusted retail electric utility sales grow by approximately 1.6 percent to 2.0 percent.

Weather-adjusted retail firm natural gas sales grow by approximately 0.0 percent to 1.0 percent.

Short-term wholesale and commodity trading margins are within a range of $25 million to $35 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 approximately 4 percent.

Depreciation expense is projected to increase approximately $5 million to $15 million over 2006 results, reflecting the MPUC s approval to extend the depreciation life of the Monticello nuclear plant and other smaller adjustments.

Interest expense increases approximately $30 million to $40 million over 2006 results.

Allowance for funds used during construction-equity increases approximately $10 million to $15 million over 2006 results.

The effective tax rate for continuing operations is approximately 32 percent to 35 percent.

Average common stock and equivalents total approximately 434 million shares.

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

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

Key Assumptions for 2008:

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

Regulatory approval of various riders associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, which are expected to increase revenue by approximately $65 million to $75 million over projected 2007 levels.

Reasonable regulatory outcomes in Wisconsin electric and gas rate cases, New Mexico electric rate case, Texas electric rate case and North Dakota electric rate case.

No material incremental accruals related to the SPS regulatory proceedings.

Weather-adjusted retail electric utility sales grow by approximately 1.8 percent to 2.2 percent.

Weather-adjusted retail firm natural gas sales grow by approximately 0.0 percent to 1.0 percent.

Short-term wholesale and commodity trading margins are within a range of $20 million to $30 million.

Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $45 million to $55 million over projected 2007 levels. We expect regulatory recovery of approximately $12 million of the increase in capacity costs at SPS. Capacity costs at PSCo are recovered under the Purchased Capacity Cost Adjustment.

Utility operating and maintenance expenses increase between 3 percent and 4 percent.

Depreciation expense is projected to increase approximately $60 million to $70 million over projected 2007 levels.

Interest expense increases approximately $25 million to $35 million over projected 2007 levels.

Allowance for funds used during construction-equity increases approximately $35 million to $45 million over projected 2007 levels.

The effective tax rate for continuing operations is approximately 32 percent to 35 percent.

Average common stock and equivalents total approximately 438 million shares.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Internal Controls Over Financial Reporting

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

Part II OTHER INFORMATION

Item 1. Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. After consultation with legal counsel, Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters. See Notes 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 consolidated financial statements in its Current Report on Form 8-K filed on Aug. 8, 2007 for a description of certain legal proceedings presently pending.

Item 1A. Risk Factors

Xcel Energy s risk factors are documented in Item 1A of Part I of its 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 and the Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, 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, the terms of which have been accepted by the IRS and the Department of Justice and require Xcel Energy to make certain payments to the government and surrender the COLI policies by Oct. 31, 2007.

On Sept. 20, 2007, Xcel Energy submitted its formal offer in compromise to settle the dispute relating to the proper tax treatment of the COLI policies beginning with tax year 1993 and for all years thereafter. By letter dated Sept. 21, 2007, the United States accepted the terms of that settlement offer. The terms of the final settlement are essentially the same as the settlement in principle reached on June 19, 2007. The U.S. government s letter terminates the tax litigation pending between the parties for tax years 1993-2002 and also specifies the agreed tax treatment for certain aspects of those policies for subsequent tax years. See Note 4 to Xcel Energy s consolidated financial statements for additional disclosure related to the COLI settlement.

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

None.

Item 6. Exhibits

The following Exhibits are filed with this report:

4.01	Supplemental Indenture, dated Aug. 1, 2007, between Public Service Company of Colorado (a Colorado corporation) and U.S. Bank Trust National Association, as successor Trustee. (Exhibit 4.01 to PSCo Form 8-K (file no. 001-3280) dated Aug. 14, 2007).
10.01	Letter dated Sept. 19, 2007, from Xcel Energy Inc. to the U.S. Department of Justice (DOJ) submitting its offer to settle the COLI tax dispute and Letter dated Sept. 21, 2007 from the DOJ to Xcel Energy Inc. accepting the settlement offer.
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

Oct. 26, 2007