Penumbra Inc
Form 10-Q
August 07, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018
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: 001-37557

Penumbra, Inc.
(Exact name of registrant as specified in its charter)

Delaware	05-0605598
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Penumbra Place Alameda, CA	94502
(Address of principal executive offices)	(Zip code)

(510) 748-3200
(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes: x No: o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes: x No: o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer a smaller reporting company or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	o
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o
Emerging growth company	o		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with accounting standards provided pursuant to Section 13(a) of the Exchange Act. o
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes: o No: x

As of July 24, 2018, the registrant had 34,379,354 shares of common stock, par value $0.001 per share, outstanding.

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PART I - FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS.

Penumbra, Inc.
Condensed Consolidated Balance Sheets
(unaudited)
(in thousands)

	June 30, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$59,705	$ 50,637
Marketable investments	147,185	163,954
Accounts receivable, net of doubtful accounts of $1,571 and $1,290 at June 30, 2018 and December 31, 2017, respectively	74,059	58,007
Inventories	97,556	94,901
Prepaid expenses and other current assets	13,994	14,735
Total current assets	392,499	382,234
Property and equipment, net	33,719	30,899
Intangible assets, net	27,344	23,778
Goodwill	7,977	8,178
Long-term investments (Note 3)	2,597	3,872
Deferred taxes	34,129	26,690
Other non-current assets	1,049	1,016
Total assets	$499,314	$ 476,667
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$7,432	$ 6,757
Accrued liabilities	42,255	44,825
Total current liabilities	49,687	51,582
Deferred rent	7,430	6,199
Other non-current liabilities	16,998	18,478
Total liabilities	74,115	76,259
Commitments and contingencies (Note 8)		
Stockholders' equity:		
Common stock	34	33
Additional paid-in capital	404,493	396,810
Accumulated other comprehensive (loss) income	(661)	1,569
Retained earnings	21,333	1,996
Total stockholders' equity	425,199	400,408
Total liabilities and stockholders' equity	$499,314	$ 476,667

See accompanying notes to the unaudited condensed consolidated financial statements

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Penumbra, Inc.
Condensed Consolidated Statements of Operations and Comprehensive Income (Loss)
(unaudited)
(in thousands, except share and per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue	$ 109,638	$ 80,589	$ 212,339	$ 153,802
Cost of revenue	37,386	29,660	73,530	55,164
Gross profit	72,252	50,929	138,809	98,638
Operating expenses:				
Research and development	8,193	8,094	16,206	15,128
Sales, general and administrative	54,776	44,163	109,275	86,884
Total operating expenses	62,969	52,257	125,481	102,012
Income (loss) from operations	9,283	(1,328)	13,328	(3,374)
Interest income, net	720	624	1,469	1,268
Other expense, net	(340)	(214)	(630)	(563)
	$ 0.51	$ 0.60	$ 1.11	$ 1.06
Income from discontinued operations				
Earnings per share basic	$ 0.51	$ 0.60	$ 1.11	$ 1.06
Earnings per share diluted				
Income from continuing operations	$ 0.51	$ 0.59	$ 1.10	$ 1.03
Income from discontinued operations				0.01
Earnings per share diluted	$ 0.51	$ 0.59	$ 1.10	$ 1.04
Cash dividends declared per common share	$ 0.24	$ 0.23	$ 0.71	$ 0.68

See Notes to Consolidated Financial Statements

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

(Thousands of Dollars)

	Nine Months Ended Sept. 30, 2008	Nine Months Ended Sept. 30, 2007
Operating activities		
Net income	$ 481,478	$ 443,305
Remove loss (income) from discontinued operations	684	(2,376)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	676,691	645,007
Nuclear fuel amortization	46,765	38,570
Deferred income taxes	199,155	187,314
Amortization of investment tax credits	(5,824)	(7,282)
Allowance for equity funds used during construction	(45,478)	(25,294)
Undistributed equity in earnings of unconsolidated affiliates	(1,835)	(1,632)
Share-based compensation expense	17,961	14,996
Net realized and unrealized hedging and derivative transactions	(34,049)	(16,269)
Changes in operating assets and liabilities:		
Accounts receivable	128,186	122,216
Accrued unbilled revenues	237,358	19,655
Inventories	(195,722)	(25,223)
Recoverable purchased natural gas and electric energy costs	(25,752)	207,586
Other current assets	21,794	(4,448)
Accounts payable	(198,877)	(247,667)
Net regulatory assets and liabilities	(47,765)	(34,127)
Other current liabilities	11,951	55,368
Change in other noncurrent assets	407	(22,288)
Change in other noncurrent liabilities	(44,172)	(8,335)
Operating cash flows provided by (used in) discontinued operations	(11,494)	57,237
Net cash provided by operating activities	1,211,462	1,396,313
Investing activities		
Utility capital/construction expenditures	(1,522,422)	(1,481,693)
Allowance for equity funds used during construction	45,478	25,294
Purchase of investments in external decommissioning fund	(643,497)	(499,991)
Proceeds from the sale of investments in external decommissioning fund	610,953	467,447
Nonregulated capital expenditures and asset acquisitions	(943)	(958)
Investment in WYCO	(73,038)	
Cash obtained from consolidation of NMC		38,950
Change in restricted cash	24,132	(4,881)
Other investments	(25,678)	10,578
Net cash used in investing activities	(1,585,015)	(1,445,254)
Financing activities		
Repayment of short-term borrowings net	(824,560)	(206,075)
Proceeds from issuance of long-term debt	1,682,393	1,162,404
Repayment of long-term debt, including reacquisition premiums	(200,041)	(290,243)
Early participation payments on debt exchange		(4,859)
Proceeds from issuance of common stock	351,357	8,970
Dividends paid	(303,157)	(281,249)
Net cash provided by financing activities	705,992	388,948

Net increase in cash and cash equivalents		332,439		340,007
Net increase (decrease) in cash and cash equivalents discontinued operations		416		(16,557)
Cash and cash equivalents at beginning of year		51,120		37,458
Cash and cash equivalents at end of quarter	$	383,975	$	360,908
Supplemental disclosure of cash flow information:				
Cash paid for interest (net of amounts capitalized)	$	363,439	$	309,620
Cash paid for income taxes (net of refunds received)		49,943		(11,163)
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	27,845	$	69,192
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	48,872	$	45,791
Issuance of common stock for senior convertible notes				125,632

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

(Thousands of Dollars)

	Sept. 30, 2008	Dec. 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 383,975	$ 51,120
Accounts receivable, net	823,394	951,580
Accrued unbilled revenues	494,601	731,959
Inventories	727,332	531,610
Recoverable purchased natural gas and electric energy costs	99,167	73,415
Derivative instruments valuation	155,322	94,554
Prepayments and other	249,038	244,134
Current assets held for sale and related to discontinued operations	97,849	128,821
Total current assets	3,030,678	2,807,193
Property, plant and equipment, net	17,554,991	16,675,689
Other assets:		
Nuclear decommissioning fund and other investments	1,239,984	1,372,098
Regulatory assets	1,364,080	1,115,443
Prepaid pension asset	598,775	568,055
Derivative instruments valuation	337,388	383,861
Other	221,180	142,078
Noncurrent assets held for sale and related to discontinued operations	153,654	120,310
Total other assets	3,915,061	3,701,845
Total assets	$ 24,500,730	$ 23,184,727
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 994,607	$ 637,535
Short-term debt	264,000	1,088,560
Accounts payable	863,888	1,079,345
Taxes accrued	206,249	240,443
Dividends payable	107,607	99,682
Derivative instruments valuation	125,830	58,811
Other	451,130	419,209
Current liabilities held for sale and related to discontinued operations	10,015	17,539
Total current liabilities	3,023,326	3,641,124
Deferred credits and other liabilities:		
Deferred income taxes	2,746,748	2,553,526
Deferred investment tax credits	107,090	112,914
Asset retirement obligations	1,371,162	1,315,144
Regulatory liabilities	1,433,464	1,389,987
Pension and employee benefit obligations	519,557	576,426
Derivative instruments valuation	339,360	384,419
Customer advances	321,919	305,239
Other	179,100	137,422
Noncurrent liabilities held for sale and related to discontinued operations	19,886	20,384
Total deferred credits and other liabilities	7,038,286	6,795,461

Commitments and contingent liabilities				
Capitalization:				
Long-term debt		7,485,798		6,342,160
Preferred stockholders equity authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800		104,980		104,980
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: Sept. 30, 2008 448,615,691 Dec. 31, 2007 428,782,700		6,848,340		6,301,002
Total liabilities and equity	$	24,500,730	$	23,184,727

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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, 2008 and 2007						
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 772,379	$ (9,294)	$ 5,987,692
Net income				254,817		254,817
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $115					446	446
Net derivative instrument fair value changes during the period, net of tax of $1,042					(2,235)	(2,235)
Comprehensive income for the period						253,028
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	$ 929,554	$ (11,083)	$ 6,157,379
Balance at June 30, 2008	430,917	$ 1,077,292	$ 4,306,239	$ 1,017,488	$ (26,549)	$ 6,374,470
Net income				222,789		222,789
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $195					273	273
Net derivative instrument fair value changes during the period, net of tax of $(1,741)					(2,522)	(2,522)
Unrealized loss - marketable securities, net of tax of $(87)					(123)	(123)
Comprehensive income for the period						220,417
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(106,545)		(106,545)
Issuances of common stock	17,699	44,247	311,340			355,587
Share-based compensation			5,471			5,471
Balance at Sept. 30, 2008	448,616	$ 1,121,539	$ 4,623,050	$ 1,132,672	$ (28,921)	$ 6,848,340

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

(UNAUDITED)
(Thousands)

	Common Stock Issued		Additional		Accumulated	Total
			Paid In	Retained	Other Comprehensive	Common Stockholders
	Shares	Par Value	Capital	Earnings	Income (Loss)	Equity
Nine months ended Sept. 30, 2008 and 2007						
Balance at Dec. 31, 2006	407,297	$ 1,018,242	$ 4,043,657	$ 771,249	$ (16,326)	$ 5,816,822
FIN 48 adoption				2,207		2,207
Net income				443,305		443,305
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $345					1,339	1,339
Net derivative instrument fair value changes during the period, net of tax of $2,926					3,900	3,900
Unrealized gain - marketable securities, net of tax of $2					4	4
Comprehensive income for the period						448,548
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	$ 929,554	$ (11,083)	$ 6,157,379
Balance at Dec. 31, 2007	428,783	$ 1,071,957	$ 4,286,917	$ 963,916	$ (21,788)	$ 6,301,002
EITF 06-4 adoption, net of tax of $(1,038)				(1,640)		(1,640)
Net income				481,478		481,478
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $1,071					330	330
Net derivative instrument fair value changes during the period, net of tax of $(2,808)					(7,240)	(7,240)
Unrealized loss - marketable securities, net of tax of $(154)					(223)	(223)
Comprehensive income for the period						474,345
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(307,902)		(307,902)

Issuances of common stock	19,833	49,582	318,881			368,463
Share-based compensation			17,252			17,252
Balance at Sept. 30, 2008	448,616	$ 1,121,539	$ 4,623,050	$ 1,132,672	$ (28,921)	$ 6,848,340

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of Sept. 30, 2008, and Dec. 31, 2007; the results of its operations and changes in stockholders equity for the three and nine months ended Sept. 30, 2008 and 2007; and its cash flows for the nine months ended Sept. 30, 2008 and 2007. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The Dec. 31, 2007 balance sheet information has been derived from the audited 2007 financial statements. For further information, refer to the Consolidated Financial Statements and notes thereto, included in the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007, filed with the Securities and Exchange Commission on Feb. 20, 2008. Due to the seasonality of Xcel Energy s electric and natural gas sales, such interim results are not necessarily an appropriate base from which to project annual results.

1. Significant Accounting Policies

Except to the extent updated or described below, the significant accounting policies set forth in Note 1 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Fair Value Measurements Xcel Energy presents cash equivalents, interest rate derivatives, commodity derivatives, and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. Cash equivalents are recorded at cost plus accrued interest to approximate fair value. Changes in the observed trading prices and liquidity of cash equivalents, including commercial paper and money market funds, are also monitored as additional support for determining fair value, and losses are recorded in earnings if fair value falls below recorded cost. For interest rate derivatives, quoted prices based primarily on observable market price curves are used as a primary input to establish fair value. For commodity derivatives, the most observable inputs available are used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use quoted prices for similar contracts, or internally prepared valuation models as primary inputs to determine fair value. For the nuclear decommissioning fund, published trading data and pricing models using the most observable inputs available are utilized to estimate fair value for each class of security.

2. Recently Issued Accounting Pronouncements

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

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

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

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Business Combinations (SFAS No. 141 (revised 2007)) In December 2007, the FASB issued SFAS No. 141R, which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. Xcel Energy will evaluate the impact of SFAS No. 141R on its consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

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

Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161) In March 2008, the FASB issued SFAS No. 161, which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity s financial position, financial performance and cash flows. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008, with early application encouraged. Xcel Energy is currently evaluating the impact of adoption of SFAS No. 161 on its consolidated financial statements.

The Hierarchy of Generally Accepted Accounting Principles (GAAP) (SFAS No. 162) In May 2008, the FASB issued SFAS No. 162, which establishes the GAAP hierarchy, identifying the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements. SFAS No. 162 is effective Nov. 15, 2008. Xcel Energy does not believe that implementation of SFAS No. 162 will have any material impact on its consolidated financial statements.

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

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

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3. Selected Balance Sheet Data

(Thousands of Dollars)		Sept. 30, 2008		Dec. 31, 2007
Accounts receivable, net:				
Accounts receivable	$	876,026	$	1,000,981
Less allowance for bad debts		(52,632)		(49,401)
	$	823,394	$	951,580
Inventories:				
Materials and supplies	$	162,742	$	152,770
Fuel		221,561		142,764
Natural gas		343,029		236,076
	$	727,332	$	531,610

(Thousands of Dollars)		Sept. 30, 2008		Dec. 31, 2007
Property, plant and equipment, net:				
Electric utility plant	$	21,327,109	$	20,313,313
Natural gas utility plant		3,020,098		2,946,455
Common utility and other property		1,500,427		1,475,325
Construction work in progress		1,924,974		1,810,664
Total property, plant and equipment		27,772,608		26,545,757
Less accumulated depreciation		(10,451,874)		(10,049,927)
Nuclear fuel		1,572,392		1,471,229
Less accumulated amortization		(1,338,135)		(1,291,370)
	$	17,554,991	$	16,675,689

4. Discontinued Operations

A summary of the subsidiaries presented as discontinued operations is discussed below. Results of operations for divested businesses are reported, for all periods presented, as discontinued operations. In addition, the remaining assets and liabilities related to the businesses divested or discontinued have been reclassified to assets and liabilities held for sale and related to discontinued operations in the consolidated balance sheets. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets and net operating loss (NOL) and tax credit carryforwards, originally from discontinued operations, that will be deductible in future years.

Nonregulated Subsidiaries

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

Summarized Financial Results of Discontinued Operations

(Thousands of Dollars)		2008		2007
Three months ended Sept. 30,				
Operating income, interest and other income, net	$	53	$	1,172
Pretax income from discontinued operations		53		1,172
Income tax expense (benefit)		(41)		1,075
Net income from discontinued operations	$	94	$	97
Nine months ended Sept. 30,				
Operating revenues	$		$	36
Operating income, interest and other income, net		253		2,971
Pretax income from discontinued operations		253		3,007
Income tax expense		937		631
Net income (loss) from discontinued operations	$	(684)	$	2,376

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

(Thousands of Dollars)		Sept. 30, 2008		Dec. 31, 2007
Cash	$	7,208	$	6,792
Accounts receivable, net		593		913
Deferred income tax benefits		86,958		118,919
Other current assets		3,090		2,197
Current assets related to discontinued operations	$	97,849	$	128,821
Deferred income tax benefits	$	124,304	$	97,284
Other noncurrent assets		29,350		23,026
Noncurrent assets related to discontinued operations	$	153,654	$	120,310
Accounts payable	$	876	$	1,060
Other current liabilities		9,139		16,479
Current liabilities related to discontinued operations	$	10,015	$	17,539
Noncurrent liabilities related to discontinued operations	$	19,886	$	20,384

5. Income Taxes

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) Xcel Energy files a consolidated federal income tax return and state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns.

In the first quarter of 2008, the Internal Revenue Service (IRS) completed an examination of Xcel Energy s federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. Tax year 2004 is the earliest open year and the statute of limitations applicable to Xcel Energy s 2004 federal income tax return remains open until Dec. 31, 2009. In the third quarter of 2008, the IRS commenced an examination of tax years 2006 and 2007.

In the first quarter of 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an audit through tax year 2005. No material adjustments were proposed for these state audits. As of Sept. 30, 2008, Xcel Energy s earliest open tax years in which an audit can be initiated by state taxing authorities in its major operating jurisdictions are as follows: Colorado-2004, Minnesota-2004, Texas-2004 and Wisconsin-2003. There currently are no state income tax audits in progress.

The amount of unrecognized tax benefits reported in continuing operations was $26.3 million on Dec. 31, 2007, and $35.7 million on Sept. 30, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $4.3 million on Dec. 31, 2007 and $6.6 million on Sept. 30, 2008. These unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryovers reported in continuing operations of $7.8 million on Dec. 31, 2007 and $11.4 million on Sept. 30, 2008 and NOL and tax credit carryovers reported in discontinued operations of $17.8 million on Dec. 31, 2007 and $25.7 million on Sept. 30, 2008.

The unrecognized tax benefit balance reported in continuing operations included $9.8 million and $10.3 million of tax positions on Dec. 31, 2007 and Sept. 30, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $16.5 million and $25.4 million of tax positions on Dec. 31, 2007 and Sept. 30, 2008, respectively, for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The increase in the unrecognized tax benefit balance reported in continuing operations of $7.7 million from July 1, 2008 to Sept. 30, 2008, was due to the addition of similar uncertain tax positions related to ongoing activity. Xcel Energy s amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months as the IRS audit of 2006 and 2007 progresses and when state audits resume. However, at this time, it is not reasonably possible to estimate an overall range of possible change.

The liability for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryovers. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the third quarter of 2008 was $0.3 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $5.8 million on Dec. 31, 2007 and $5.3 million on Sept. 30, 2008. The amount of interest income related to unrecognized tax benefits reported within interest charges in discontinued operations in the third quarter of 2008 was $0.2 million.

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The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $0.5 million on Dec. 31, 2007 and $1.2 million on Sept. 30, 2008.

No amounts were accrued for penalties in the third quarter of 2008. The liability for penalties related to unrecognized tax benefits reported in continuing operations was $1.0 million on Dec. 31, 2007 and Sept. 30, 2008.

Other Income Tax Matters Income taxes for continuing operations increased by $1 million for the third quarter of 2008, compared with 2007. The effective tax rate for continuing operations was 35.3 percent for the third quarter of 2008, compared with 32.2 percent for the same period in 2007. The higher effective tax rate for third quarter 2008 as compared with 2007 was primarily due to benefits from the corporate-owned life insurance policies (COLI) in the third quarter of 2007. Without these benefits, the effective tax rate for the third quarter of 2007 would have been 34.8 percent.

Income taxes for continuing operations increased by $13 million for the first nine months of 2008, compared with 2007. The increase in income tax expense was primarily due to an increase in pretax income in 2008. The effective tax rate for continuing operations was 34.5 percent for the first nine months of 2008, compared with 35.2 percent for the same period in 2007.

COLI On June 19, 2007, a settlement in principle was reached between Xcel Energy and representatives of the United States Government regarding PSCo s right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo.

In September 2007, Xcel Energy and the United States finalized a settlement, which terminated the tax litigation pending between the parties. As a result of the settlement, the lawsuit filed by Xcel Energy in the United States District Court has been dismissed and the Tax Court proceedings are in the process of being dismissed. Xcel Energy paid 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.

6. Rate Matters

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

NSP-Minnesota

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

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider In November 2006, the MPUC approved a TCR rider pursuant to legislation, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. In December 2007, NSP-Minnesota filed adjustments to the TCR rate factors and implemented a rider to recover $18.5 million beginning Jan. 1, 2008. In March 2008, the MPUC approved the 2008 cost recovery, but required certain procedural changes for future TCR filings if costs are disputed. NSP-Minnesota filed the required compliance filing in April 2008. In the fourth quarter of 2008, NSP-Minnesota expects to submit its TCR rate factors for proposed recovery in 2009.

Renewable Energy Standard (RES) Rider In March 2008, the MPUC approved an RES rider to recover the costs associated with utility-owned projects implemented in compliance with the RES adopted by the 2007 Minnesota legislature, and it was implemented on April 1, 2008. Under the rider, NSP-Minnesota could recover up to approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100-megawatt (MW) wind project, subject to true-up. On Aug. 29, 2008, NSP-Minnesota submitted the RES rider for recovery of approximately $22 million in 2009 attributable to the Grand Meadow wind farm and a Wind2Battery project. On Sept. 15, 2008, the Minnesota Office of Energy Security (OES) issued comments recommending removal of the Wind2Battery project from the RES, pending MPUC approval of the project. On Sept. 23, 2008, NSP-Minnesota filed reply comments removing the project and reducing the recovery request by $0.3 million.

Metropolitan Emissions Reduction Project (MERP) Rider On Oct. 1, 2008, NSP-Minnesota filed a proposed MERP rider for 2009 designed to recover costs related to MERP environmental improvement projects. Under this rider, NSP-Minnesota proposes to recover $114 million in 2009, an increase of approximately $23 million over 2008.

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Annual Automatic Adjustment Report for 2007 In September 2007, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2006 through June 30, 2007, which is the basis for the MPUC review of charges that flow through the fuel clause adjustment (FCA) and purchased gas adjustment (PGA) mechanisms. During that time period, $1.2 billion in fuel and purchased energy costs, including $384 million of Midwest Independent Transmission System Operator, Inc. (MISO) charges were recovered from electric customers through the FCA. In addition, approximately $590 million of purchased natural gas and transportation costs were recovered through the PGA. The OES filed its comments on the gas annual report on June 12, 2008, recommending MPUC approval. The OES submitted its comments in the electric report on June 30, 2008. While the OES made several recommendations regarding assignment of wholesale and retail costs for the recovery period and future periods, none of these recommendations are expected to have a material financial impact, as NSP-Minnesota currently returns all margins to ratepayers. NSP-Minnesota filed reply comments in July 2008. On Oct. 16, 2008, the MPUC voted to accept the 2007 gas annual automatic adjustment report. The 2007 annual electric automatic adjustment report is pending further written comments and MPUC action.

Annual Automatic Adjustment Report for 2008 In September 2008, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2007 through June 30, 2008. During that time period, $848.5 million in fuel and purchased energy costs, including $258.8 million of MISO charges, were recovered from Minnesota electric customers through the FCA. In addition, approximately $680 million of purchased natural gas and transportation costs were recovered through the PGA. The 2008 annual automatic adjustment reports are pending initial comments and MPUC action. The OES is expected to file its comments on June 15, 2009.

MISO Ancillary Service Market (ASM) Cost Recovery On May 9, 2008, NSP-Minnesota and several other Minnesota electric utilities filed jointly for MPUC regulatory approval to recover ASM costs via the Minnesota FCA cost recovery mechanism. On Aug. 8, 2008, the OES filed comments arguing the MPUC should not allow the utilities to recover ASM costs in the FCA until after the first year of ASM operations. On Sept. 30, 2008, the utilities filed joint comments opposing certain of the OES recommendations. The filing is pending MPUC action. NSP-Minnesota expects to submit similar ASM rate recovery filings to the North Dakota Public Service Commission (NDPSC) and South Dakota Public Utilities Commission (SDPUC) in the fourth quarter of 2008. MISO expects to begin ASM operations in January 2009.

Gas Meter Module Failure Approximately 8,700 customers in the St. Cloud and East Grand Forks areas of Minnesota and about 4,000 customers in the Fargo, North Dakota area were under billed for a period of time during the 2007-2008 heating season due to the failure of the automated meter reading (AMR) module installed on their natural gas meters. While the modules failed to register usage, the meters continued to function. The MPUC and NDPSC have each initiated an investigation into the module failure issue and NSP-Minnesota s response to the failure.

On July 2, 2008, NSP-Minnesota received a letter from the NDPSC requesting further information on the module failure. NSP-Minnesota responded on July 30, 2008, and participated in an informational meeting with the NDPSC on Sept. 9, 2008. Subsequent meetings between NSP-Minnesota and NDPSC staff were held in September and October 2008 to discuss NSP-Minnesota s progress in addressing various NDPSC concerns about NSP-Minnesota s response.

On Aug. 1, 2008, the MPUC opened a docket and issued a notice directing NSP-Minnesota to file information about the AMR module failure. NSP-Minnesota responded to the MPUC on Aug. 21, 2008. The Minnesota Office of Attorney General (MOAG) and the OES subsequently submitted comments on NSP-Minnesota s filing. The OES comments indicated support for the rebilling plan with certain conditions. The MOAG raised concerns about the timing of the remediation efforts, and questions whether customers should be responsible for the entire cost of the unbilled natural gas.

NSP-Minnesota believes that the meter failure did not have a material effect on the consolidated financial statements.

Annual Review of Remaining Lives On Oct. 8, 2008, the MPUC approved NSP-Minnesota s service lives, salvage rates and resulting depreciation rates for its electric and gas production facilities as well as the depreciation study for other gas and electric assets, effective Jan. 1, 2008. The net impact resulted in a reduction to depreciation expense of $5.6 million recognized in the third quarter, or $7.5 million on an annual basis.

Other

Nuclear Refueling Outage Costs In November 2007, NSP-Minnesota requested a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request sought approval to amortize refueling outage costs over the period between refueling outages to better match revenues and expenses. This request would have reduced 2008 expenses for the NSP-Minnesota jurisdiction by approximately $25 million due to deferral and amortization over an 18-month period versus expensed as incurred.

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On Sept. 16, 2008, the MPUC authorized NSP-Minnesota to use a deferral and amortization method for the nuclear refueling operating and maintenance costs effective Jan. 1, 2008. The ruling reduced operating and maintenance expenses, but also resulted in revenue deferrals. The net result is a positive adjustment to third quarter earnings of approximately $14 million and an estimated impact to full year earnings of approximately $18 million.

Pending Regulatory Proceedings NDPSC and SDPUC

NSP-Minnesota North Dakota Electric Rate Case In December 2007, NSP-Minnesota filed a request with the NDPSC to increase North Dakota retail electric rates by $20.5 million, which would be an $18.2 million impact to NSP-Minnesota due to the transfer of certain costs and revenues between base rates and the fuel cost recovery mechanism. The request was based on an 11.50 percent return on equity (ROE), an equity ratio of 51.77 percent, and a rate base of approximately $242 million. Interim rates of $17.2 million became effective in February 2008.

NSP-Minnesota and the NDPSC staff reached a stipulation settlement in the rate case in which both parties recommended an ROE of 10.75 percent, with a sharing mechanism for earnings above 10.75 percent. This stipulation settlement is subject to approval by the NDPSC. In June 2008, NSP-Minnesota filed rebuttal testimony and reduced its requested rate increase to $17.9 million, a net impact of $15.7 million to NSP-Minnesota, which reflects a 10.75 percent ROE and other adjustments.

Evidentiary hearings were held in June 2008. The updated NDPSC advocacy staff s overall recommendation following the hearing is a base rate increase of $4.9 million, a net impact of $2.5 million to NSP-Minnesota, with recommended disallowances for costs associated with NSP-Minnesota s compliance with Minnesota renewable energy requirements, investments in environmental improvements and power plant life extensions through NSP-Minnesota s MERP, and recommended changes in treatment of depreciation costs.

In its briefs filed on Aug. 22, 2008 and Oct. 1, 2008, advocacy staff has suggested that, in the alternative to its earlier recommendations in testimony, the NDPSC could dismiss the rate case on the basis that NSP-Minnesota did not meet the burden of proof. The NDPSC will likely make a decision regarding the rate case in November, with final rates expected to be effective in the first quarter of 2009.

Nuclear Refueling Outage Costs In late 2007, NSP-Minnesota filed with both the NDPSC and SDPUC a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request is comparable to that filed with the MPUC. In February 2008, the NDPSC approved the request, indicating that appropriate cost recovery levels would be determined in the pending electric rate case.

The SDPUC approved the NSP-Minnesota s request to change the accounting method for nuclear refueling outage operating and maintenance cost from a direct expense method to a method that amortizes these costs over the period between outages.

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

MISO Long-Term Transmission Pricing In October 2005, MISO filed a proposed change to its Transmission and Energy Markets Tariff of MISO (TEMT) to regionalize future cost recovery of certain high voltage transmission projects to be constructed for reliability improvements. The tariff, called the Regional Expansion Criteria Benefits phase I (RECB I) and a subsequent proposal based on regional economic benefits (RECB II), would recover varying percentages of eligible reliability transmission costs from all transmission service customers in the MISO 15 state region. In November 2006, the FERC issued an order accepting the RECB I tariff, including the 20 percent limitation, which is the cap on the portion of transmission expansion costs that would be regionalized and recovered from all loads in the MISO region, with 80 percent allocated to the pricing zone where the transmission facilities are constructed. In December 2006, the Public Service Commission of Wisconsin (PSCW) and other parties filed an appeal of the RECB I order to the U.S. federal Court of Appeals for the District of Columbia. The appeal is pending. In March 2007, the FERC issued an order approving most aspects of the RECB II proposal.

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

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NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings PSCW

Base Rate

Electric and Gas 2008 Rate Case In January 2008, the PSCW issued the final written order in NSP-Wisconsin s 2008 test year rate case, approving an electric rate increase of approximately $39.4 million, or 8.1 percent, and a natural gas rate increase of $5.3 million, or 3.3 percent. The rate increase was based on a 10.75 percent ROE and a 52.5 percent common equity ratio. New rates went into effect Jan. 9, 2008.

Electric Limited Reopener 2009 Rate Case On Aug. 1, 2008, NSP-Wisconsin filed an application with the PSCW requesting authority to increase retail electric rates by $47.1 million, which represents an overall increase of 8.6 percent. In the application, NSP-Wisconsin requested the PSCW to reopen the 2008 base rate case for the limited purpose of adjusting 2009 base electric rates to reflect forecasted increases in production and transmission costs, as authorized by the PSCW. Of the total amount requested, approximately $22.7 million was for anticipated increases in fuel and purchased power expenses, approximately $18.8 million was for capital investments in electric generation and transmission projects and the remaining $5.6 million was for various operating and maintenance expenses associated with generation and transmission. No changes were requested to the capital structure or authorized ROE authorized by the PSCW in the 2008 base rate case.

On Oct. 10, 2008, the PSCW staff filed direct testimony recommending adjustments to the filed revenue deficiency that, in total, would reduce the $47.1 million requested increase to approximately $16.0 million. Approximately $26.1 million of the $31.1 million reduction is related to updated data since the filing was prepared and would not result in any financial impact to NSP-Wisconsin.

- $20.6 million is due to a lower forecast of 2009 fuel and purchased power costs, caused by declining market prices since the filing was made. PSCW staff requested the company to update the fuel and purchased power forecast again just prior to the PSCW decision in this case.

- $5.5 million is due to a change in recovery method for nuclear outage costs from the direct expense method used in the initial August 2008 filing to the deferral and amortization method. On Sept. 16, 2008, NSP-Minnesota received approval for this change in recovery method from the MPUC, and as a result, NSP-Wisconsin will see a reduction in nuclear outage expense billed through the interchange agreement in 2009. (See Pending and Recently Concluded Regulatory Proceedings MPUC.)

The remaining $5.0 million reduction is the net effect of a number of smaller adjustments recommended by PSCW staff, including a $1.8 million adjustment to the fixed charge component of the Interchange Agreement based on historic actual to budget spending patterns, and a $1.6 million adjustment to reflect an increase to the sales forecast. At this time, NSP-Wisconsin is in the process of reviewing PSCW staff testimony to determine the extent to which it will contest the adjustments in rebuttal testimony.

Although the Wisconsin Industrial Energy Group (WIEG), Wal-Mart Stores East, LP (Wal-Mart) and the Citizen s Utility Board (CUB) participated in the pre-hearing conference in this proceeding, none of the parties submitted testimony concerning the revenue deficiency.

On Oct. 17, 2008 the PSCW staff and Wal-Mart submitted testimony on rate design issues. The PSCW staff is recommending a slightly below-average increase for residential and small commercial customers and an above-average increase for medium and large commercial and industrial customers. The PSCW staff rate design is generally consistent with the rate design proposed by NSP-Wisconsin, but is based on the lower staff-adjusted revenue requirements. Wal-Mart is recommending an across-the-board percentage increase. All rebuttal testimony, on both revenue requirements and rate design, is due Oct. 24, 2008.

A hearing to address NSP-Wisconsin s rate request is scheduled on Oct. 31, 2008 at the PSCW. The PSCW has also scheduled public meetings concurrently in the Wisconsin cities of Eau Claire, La Crosse and Madison by video conference on Nov. 3, 2008. A final PSCW decision on the request is expected in December 2008.

Other

Nuclear Refueling Outage Costs As noted above, on Sept. 16, 2008, the MPUC approved NSP-Minnesota s request to adopt the deferral-and-amortization method of accounting for costs associated with refueling outages at its nuclear plants, effective Jan. 1, 2008. NSP-Wisconsin s 2008 Wisconsin retail electric retail rates were set based on the previous direct-expense accounting method, and will recover costs associated with 2008 refueling outages in 2008. For ratemaking purposes, NSP- Wisconsin will switch to the deferral and amortization method effective Jan. 1, 2009. To reflect timing differences between when the revenue was received from customers

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versus when the corresponding expense will be billed through the interchange agreement, NSP-Wisconsin recorded a regulatory liability of $4.1 million. The regulatory liability will be fully amortized by the end of 2010.

2007 Electric Fuel Cost Recovery In October 2007, the PSCW issued an order approving an interim fuel surcharge, subject to refund, under the provisions of the Wisconsin fuel rules. The interim surcharge became effective Oct. 15, 2007 and was terminated upon implementation of new base electric rates on Jan. 9, 2008. During the time period it was in effect, the surcharge generated approximately $1.3 million in additional revenue. Despite the additional surcharge revenue, NSP-Wisconsin s actual fuel costs for 2007 were approximately $11.9 million higher than fuel revenues recovered in rates.

On June 30, 2008, NSP-Wisconsin filed a stipulation with the PSCW indicating the parties in this docket are in agreement that NSP-Wisconsin s actual fuel cost during the time period interim rates were in effect were higher than fuel costs authorized by the PSCW and no final hearing to determine a refund amount is necessary. The PSCW administrative law judge (ALJ) issued an order closing the docket on Sept. 26, 2008.

2008 Electric Fuel Cost Recovery On May 2, 2008, the PSCW approved NSP-Wisconsin s request to increase Wisconsin retail electric rates on an interim basis. The PSCW approved a $19.7 million surcharge, or 3.8 percent, on an annual basis, to recover increases in fuel and purchased power costs. NSP-Wisconsin expects that the surcharge will generate approximately $12.6 million in additional revenue in 2008. The increase in fuel costs is primarily driven by fuel and purchased power costs, including replacement power costs associated with unplanned plant outages. The increased rates went into effect on May 6, 2008. The revenues that NSP-Wisconsin collects are subject to refund with interest at a rate of 10.75 percent, pending PSCW review and final approval. At this time, NSP-Wisconsin expects that the PSCW will leave the interim rates in effect for the remainder of 2008, conducting the final review in 2009, after 2008 actual fuel costs are known.

NSP-Wisconsin actual retail fuel costs through September were approximately $6.9 million less than assumed in the April 2008 forecast used to set the interim fuel surcharge. Actual fuel costs have been running lower than this forecast primarily due to lower load and lower market prices for fuel and purchased power. Based on actual fuel costs to date, NSP-Wisconsin has established a reserve of $5.0 million to reflect the likelihood that the PSCW will order the company to refund a portion of the revenues collected through the interim surcharge. Further, NSP-Wisconsin anticipates fuel costs in the fourth quarter of 2008 will continue to be less than assumed in the April 2008 forecast used to set the interim fuel surcharge. Notwithstanding the interim surcharge and lower than forecast fuel costs, NSP-Wisconsin expects that 2008 calendar year fuel costs will exceed authorized revenues by approximately $3.7 million, net of the anticipated refund.

Fuel Cost Recovery Rulemaking In June 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. The statutes authorize the PSCW to approve a rate increase for these utilities to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In August 2007, the PSCW staff issued its draft revisions to the fuel rules and requested comments. 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 July 3, 2008, the PSCW issued its notice of hearing in the rulemaking and requested public comments on the proposed revisions to the fuel rules. The proposed revisions to the rules were substantively the same as the version issued in August 2007, described above. A public hearing was held Aug. 4, 2008 and written comments were filed by the parties on Aug. 6, 2008. The utilities subject to the fuel rules, including NSP-Wisconsin, the Wisconsin Utilities Association, and Wisconsin Utility Investors, Inc. filed comments generally supporting the revised rule. An ad hoc coalition of intervenors, consisting of consumer and industrial customer groups, filed joint comments in opposition to the proposed rules.

The PSCW did not forward the proposed rules to the legislature for approval before the statutory deadline for action in the 2007-08 legislative session, and no further action is expected this year. At this time it is uncertain what, if any, additional action the PSCW will take with respect to this rulemaking, or the fuel rules in general.

Bay Front Emission Controls Certificate of Authority In March 2008, the PSCW issued a certificate of authority and order approving NSP-Wisconsin s application to install equipment relating to combustion improvement and nitrogen oxide (NOx) emission controls in boilers 1 and 2 at the Bay Front power plant in Ashland, Wis. Construction began in May and is expected to be completed in the fourth quarter of 2008.

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PSCo

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

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Adjustment (TCA) Rider In September 2007, PSCo filed with the CPUC a request to implement a TCA. In December 2007, the CPUC approved PSCo s application to implement the TCA. The CPUC limited the scope of the costs that could be recovered through the rider during 2008 to only those costs associated with transmission investment made after the new legislation authorizing the rider became effective on March 26, 2007. The CPUC also required PSCo to base its revenue requirement calculation on a thirteen-month average net transmission plant balance. As a result of the CPUC s decision, PSCo implemented a rider on Jan. 1, 2008, expected to recover approximately $4.5 million in 2008. PSCo expects to file updates to the TCA on Nov. 3, 2008 for rates to go into effect Jan. 1, 2009.

Enhanced Demand Side Management (DSM) Program In October 2007, PSCo filed an application with the CPUC for approval to implement an expanded DSM program and to revise its DSM cost adjustment mechanism to include current cost recovery and incentives designed to reward PSCo for successfully implementing cost-effective DSM programs and measures. In July 2008, the CPUC issued an order approving PSCo s proposal to expand the DSM program and recover 100 percent of its forecasted expenses associated with the DSM program during the year in which the rider is in effect, beginning in 2009. An incentive mechanism was also approved to reward PSCo for meeting and exceeding program goals.

Pending and Recently Concluded Regulatory Proceedings FERC

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

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

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

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

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

The FERC approved the settlement agreements on June 19, 2008.

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SPS

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

Base Rate

Texas Retail Base Rate Case On June 12, 2008, SPS filed with the PUCT, and the 80 cities in SPS Texas service territory with original rate jurisdiction, a request for a Texas system retail electric general rate increase. The filing requests an overall increase in annual revenues of approximately $61.3 million, or an increase of 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue will decline by $33.1 million, primarily due to the fuel savings from SPS power purchases from the Hobbs generating facility, which is owned by Lea Power Partners, LLC (LPP). Hobbs is a natural gas combined cycle 604 MW plant in New Mexico, which came on line in September 2008.

The rate filing is based on a 2007 calendar year test year adjusted for known and measurable changes and includes a requested rate of ROE of 11.25 percent, net rate base of approximately $989.4 million allocated to the Texas retail jurisdiction, and an equity ratio of 51.0 percent.

In SPS last Texas rate case, the parties agreed that SPS should seek, in this rate filing, interim rate relief of $18 million per year for the LPP purchase agreement. The interim rates went into effect when the LPP plant came on line in September 2008. The deadline for the PUCT to act on SPS request is March 31, 2009.

The filing with the PUCT also includes a request to reconcile (i.e. seek final approval for) $1.0 billion of SPS fuel and purchased power costs for calendar years 2006 and 2007.

On Oct. 13, 2008, the Office of Public Utility Counsel (OPUC), the Association of Xcel Municipalities (AXM) and the Texas Industrial Energy Consumers (TIEC) filed testimony on the revenue requirements portion of the case.

- The OPUC recommended a reduction to SPS $94.4 million base revenue request of $27.1 million based on an ROE of 9.95 percent.
- The TIEC recommended a reduction of $28.6 million based on an ROE of 10.0 percent.
- The AXM recommended a reduction of $71.7 million, based on an ROE of 9.5 percent. AXM also recommended a $3 million disallowance of fuel costs associated with the assignment of incremental cost to a wholesale contract with EPE.

The PUCT filed testimony on Oct. 21, 2008 recommending a reduction to SPS $94.4 million base revenue request of $49.8 million based on an ROE of 10.32 percent.

The remaining procedural schedule is as follows:

- PUCT staff and intervenors cross-rebuttal testimony is expected to be filed on Oct. 28, 2008;
- SPS rebuttal testimony is expected to be filed on Nov. 4, 2008;
- The hearing on the merits is expected to begin on Nov. 12, 2008; and
- Final order expected by March 31, 2009.

On June 2, 2008, SPS filed an application for approval of an energy efficiency cost recovery factor rider. On Sept. 15, 2008, the PUCT concluded that the rule under which the application was filed does not apply to SPS, but that SPS should be allowed to seek recovery of the energy efficiency costs in this base rate case. On Oct. 3, 2008, SPS made a supplemental filing in the base rate case to request recovery of the energy efficiency costs.

John Deere Wind Complaint On June 27, 2007, several John Deere Wind Energy subsidiaries (JD Wind) filed a complaint against SPS disputing SPS payments to JD Wind for energy produced from the JD Wind projects. SPS responded that the payments to JD Wind for energy produced from its Qualifying Facility is appropriate and in accordance with SPS filed tariffs with the PUCT. The PUCT referred the complaint to the State Office of Administrative Hearings. On Aug. 14, 2008, JD Wind filed testimony claiming SPS has been underpaying JD Wind for its energy. On Sept. 15, 2008, SPS and Occidental Permian, Ltd., filed answering testimony. Hearings were held before an ALJ on Oct. 13 through 16, 2008. The matter has yet to be briefed. The ultimate outcome of this complaint proceeding is not known at this time.

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Electric and Resource Adjustment Clauses

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

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

Base Rate

New Mexico Electric Rate Case In July 2007, SPS filed with the NMPRC requesting a New Mexico retail electric general rate increase of $17.3 million annually, or 6.6 percent. The rate filing was based on a 2006 test year adjusted for known and measurable changes and included a requested ROE of 11.0 percent, an electric rate base of approximately $307.3 million and an equity ratio of 51.2 percent.

On Aug. 26, 2008, the NMPRC issued its final order authorizing an overall rate increase of $10.8 million based on a 10.18 percent ROE. This increase is based on a $7 million electric base rate increase and a rider to recover $3.8 million of restructuring costs. The NMPRC disallowed $3.5 million in rate base for historical DSM expenditures and certain rate case and prepaid pension expenses.

SPS implemented the base rates on Sept. 14, 2008. On Sept. 25, 2008, SPS filed for rehearing on certain issues. On Oct. 14, 2008, the NMPRC denied SPS motion for rehearing.

Electric and Resource Adjustment Clauses

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

Testimony was filed in the case by staff and intervenors objecting to SPS assignment of system average fuel costs to certain wholesale sales and the inclusion of certain purchased power capacity and energy payments in the FPPCAC. The testimony also proposed limits on SPS future use of the FPPCAC. Related to these issues, some intervenors requested disallowances for past periods, which in the aggregate total approximately $45 million. This claim was for the period from Oct. 1, 2001 through May 31, 2005 and does not include the value of incremental cost assigned for wholesale transactions from that date forward. Other issues in the case include the treatment of renewable energy certificates and sulfur dioxide (SO2) allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause.

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

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

A hearing on the merits of the settlement was held in April 2008. On June 3, 2008, the hearing examiner certified the unanimous stipulation to the NMPRC. The NMPRC held a hearing on Aug. 14, 2008 to enable the NMPRC to directly question the witnesses who supported the unanimous stipulation. On Aug. 26, 2008, the NMPRC issued a final order approving the unanimous stipulation.

Investigation of SPS Participation in Southwest Power Pool, Inc. (SPP) In October 2007, the NMPRC issued an order initiating an investigation to consider the prudence and reasonableness of SPS participation in the SPP Regional Transmission Organization (RTO). The investigation will consider the costs and benefits of RTO participation to SPS customers in New Mexico. SPS filed its direct testimony on July 31, 2008.

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The following procedural schedule has been established:

- Intervention deadline on Nov. 3, 2008;
- Staff and intervenor direct testimony due on Feb. 3, 2009;
- SPS rebuttal testimony due on March 6, 2009; and
- The hearing on the merits is expected to begin on March 31, 2009.

Pending and Recently Concluded Regulatory Proceedings FERC

Wholesale Rate Complaints In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer s Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustment charges to such customers (the Complaint). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS largest retail customer, intervened in the proceeding.

In May 2006, a FERC ALJ issued an initial decision in the proceeding. The ALJ found that SPS should recalculate its wholesale fuel and purchased economic energy cost adjustment clause (FCAC) billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by deducting from such costs the incremental fuel costs attributed to SPS sales of system firm capacity and associated energy to other wholesale customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales made out of temporarily excess capacity. In addition, the ALJ made recommendations on a number of base rate issues including a 9.64 percent ROE and the use of a 3-month coincident peak (3CP) demand allocator.

Golden Spread Complaint Settlement In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. On April 21, 2008, the FERC approved the Settlement with a minor modification to the formula rate proposed by the FERC and accepted by the parties. The Settlement provides for:

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

- An extended partial requirements contract at system average cost, with a capacity amount that ramps down over the period 2012 through 2019 from 500 MW to 200 MW. The extended agreement requires that the cost assignment treatment receive Texas and New Mexico state approvals and provides for alternative pricing terms and quantities to hold SPS harmless from cost disallowances in the event that adverse regulatory treatment occurs or state approvals are not obtained. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals.

- Resolution of base rates in the Complaint without any adjustment to the existing rates for the period January 2005 through June 30, 2006. The Settlement also resolves all base rate issues in SPS subsequent proceeding related to the period July 1, 2006 through Sept. 30, 2008, other than the method to be used to allocate demand related costs and provided for two sets of agreed on rates that are dependent on the ultimate resolution of that issue. If SPS prevails in its support of the 12-month coincident peak (12 CP) demand allocation method, there would be no impact to earnings for this period. As discussed below, the ALJ issued an initial decision finding that SPS proposed 12-CP demand methodology is appropriate and a hearing is not necessary.

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

Order on Wholesale Rate Complaints On April 21, 2008, the FERC issued its Order on the Complaint (the Order) applied to the remaining non-settling parties. The Order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006 for SPS full requirements customers who pay traditional cost-based rates and requires certain refunds.

Base Rates: The FERC determined: (1) the ROE should be 9.33 percent; (2) rates should be based on a 12 CP allocator; and (3) the treatment of market based rate contracts in the test year should be to credit revenues to the cost of service rather than allocating costs to the agreements. The revenue requirement established by the FERC results in proposed revenues that are estimated to be approximately $25 million, or approximately $6.9 million below the level charged these customers during this 18-month period. Rates for full requirements customers, the New Mexico Cooperatives and Cap Rock, as well as an interruptible contract with PNM for the period beginning in July 1, 2006, are the subject of settlements that have either been approved or are pending before FERC. These settlements are described in Wholesale 2005 Power Base Rate Application below.

Fuel Clause: The FERC determined that the method for calculating fuel and purchased energy cost charges to the complaining customer is to deduct from such costs incremental fuel and purchased energy costs, which it is attributing to SPS market based intersystem sales on the basis that these are opportunity sales under its precedent. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005 (the refund effective date in the case). The FERC ordered SPS to file a compliance filing calculating its refund obligation within 30 days of the date of the Order and implement the instructions in the order in calculating its FCAC charges going forward from that date. While the order is subject to interpretation with respect to aspects of the calculation of the refund obligation, SPS does not expect its refund obligation to its full requirements customers from Jan. 1, 2005 through March 31, 2008, to exceed $11 million. PNM has filed a separate complaint that any refund obligation to PNM will be determined in that docket. SPS is reviewing the Order and has not yet determined whether to seek rehearing.

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

On July 21, 2008, SPS submitted it compliance report to the FERC. In the report, SPS has calculated the base rate refund for the 18-month period to be equal to $6.1 million and the fuel refund to be equal to $4.4 million. Several wholesale customers have protested the calculations. Once the final refund amounts are approved by the FERC, interest will be added to the refund due the full requirements customers. As of Sept. 30, 2008, SPS has accrued an amount sufficient to cover the estimated refund obligation.

Wholesale 2005 Power Base Rate Application In December 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. In January 2006, the FERC conditionally accepted the proposed rates for filing and the $2.5 million power rate increase became effective on July 1, 2006, subject to refund. The FERC also set the rate increase request for hearing and settlement judge procedures. In September 2006, offers of settlement with respect to the five full-requirements customers and with respect to PNM were filed for approval. In September 2007, the FERC accepted the settlement with the full-requirements customers. In September 2008, the FERC issued an order accepting the contested partial settlement with PNM.

As noted, the Power Base Rate Application relating to Golden Spread was settled in conjunction with the Complaint Settlement discussed above. Therefore, SPS has settled with all parties in the Wholesale 2005 Power Base Rate Application, except for resolution with Golden Spread of the demand cost allocation methodology. SPS and the full-requirements customers have requested that the demand allocation issue be summarily ruled on in SPS favor. On Aug. 29, 2008, the ALJ issued an initial decision finding that SPS proposed 12 CP demand methodology is appropriate and a hearing is not necessary. Therefore, SPS will owe no refunds to Golden Spread as a result of the demand allocation methodology. Golden Spread has accepted the recommended decision. The initial decision is now pending before the FERC for final action.

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SPS Formula Transmission Rate Case In December 2007, Xcel Energy submitted an application to implement a transmission formula rate for the SPS zone of the Xcel Energy Open Access Transmission Tariff (OATT). The changed rates will affect all wholesale transmission service customers using the SPS transmission network under either the SPP Regional OATT or the Xcel Energy OATT.

The proposed rates would be updated annually each July 1 based on SPS prior year actual costs and loads plus the revenue requirements associated with projected current year transmission plant additions. The proposed ROE is 12.7 percent, including a 50 basis point adder for SPS participation in the SPP RTO. The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC accepted the proposed rates, suspending the effective date to July 6, 2008, and setting the rate filing for hearings and settlement procedures. The FERC granted a 50 basis point adder to the ROE that it will determine in this proceeding as a result of SPS participation in the SPP RTO. The filed rates, updated for 2007 actual costs and projected 2008 transmission plant additions, were placed into effect on July 6, 2008, subject to refund. The SPS and SPP rate filings are now in settlement procedures. The ultimate outcome of the rate filings is not known at this time.

SPS 2008 Wholesale Rate Case On March 31, 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. On April 21, 2008, a motion for dismissal and protest was filed by the four eastern New Mexico cooperatives.

In SPS answer to the motions to intervene and protest, SPS renewed its request for a nominal suspension of 60 days and asked the FERC to consider such a nominal suspension in exchange for SPS acceptance of two conditions. The first condition was that SPS would agree to a ROE of no more than 10.25 percent and second, SPS would agree to use a 12 CP demand allocator for the period the rates will be in effect. The SPS answer would result in an annual revenue increase of $9.9 million or an overall 3.4 percent increase.

In May 2008, the FERC accepted the answer and ordered a nominal suspension for rates to go in to effect as of the date of commercial service of the LPP plant. The LPP plant went into commercial operation on Sept. 16, 2008 and the proposed rates went into effect at that time, subject to refund. The FERC set the rate filing for hearings and settlement procedures, and the case is currently in settlement discussions. The ultimate outcome of the rate filings is not known at this time.

7. Commitments and Contingent Liabilities

Except to the extent noted below, the circumstances set forth in Notes 14, 15 and 16 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, and Note 6 to the consolidated financial statements in this Quarterly Report on Form 10-Q appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include contingencies and unresolved contingencies that are material to Xcel Energy s financial position.

Operating Leases Xcel Energy began taking power under four purchase power agreements in 2008; one during the third quarter for SPS, one during the second quarter for NSP-Minnesota and two during the second quarter for PSCo. These are being accounted for as operating leases in accordance with EITF No. 01-8, *Determining Whether an Arrangement Contains a Lease,* and SFAS No. 13, *Accounting for Leases*. Future commitments under purchase power agreements being accounted for as operating leases are:

	Purchase Power Agreement Operating Leases (Millions of Dollars)
2008	$ 39.4
2009	82.7
2010	83.1
2011	83.6
2012	84.0
Thereafter	1,553.5

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Variable Interest Entities (VIE) Xcel Energy has certain long-term power purchase agreements with independent power producing entities that contain tolling arrangements under which Xcel Energy procures the fuel required to produce the energy purchased. Xcel Energy enters into these agreements to meet electric system capacity and energy needs. Xcel Energy is not subject to risk of loss from the operations of these potential VIEs. Xcel Energy has evaluated such entities for possible consolidation under *FASB Interpretation No. 46R Consolidation of Variable Interest Entities*. We have concluded that Xcel Energy is not the primary beneficiary of these entities, and therefore, these entities are not required to be consolidated in Xcel Energy s consolidated financial statements. See additional discussion of purchased power agreements in Note 15 of the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007.

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 (PRP) and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by Xcel Energy subsidiaries, predecessors, or other entities; and third-party sites, such as landfills, to which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At Sept. 30, 2008, the liability for the cost of remediating these sites was estimated to be $71.4 million, of which $2.1 million was considered to be a current liability.

Manufactured Gas Plant Sites

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

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

In October 2004, the WDNR filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The lawsuit has been stayed. NSP-Wisconsin has recorded an estimate of its potential liability. All costs paid to the WDNR are expected to be recoverable in rates.

In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) Program accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007. In 2007, NSP-Wisconsin spent $1.5 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. In June 2007, the EPA modified its remedial investigation report to establish final remedial action objectives (RAOs) and preliminary remediation goals (PRGs) for the Ashland site. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup.

In October 2007, the EPA approved the series of reports included in the remedial investigation report. The draft feasibility study, which develops and assesses the alternatives for cleaning up the site, was prepared by NSP-Wisconsin and was submitted to the EPA in October 2007. The EPA commented on the draft feasibility study in February 2008, and a revised feasibility study addressing EPA s concerns was submitted in May 2008. Comments on the revised feasibility study were received from the EPA on Sept. 25, 2008, and the second revision of the feasibility study addressing these comments was submitted on Oct. 24, 2008. The EPA Remedy Review Board is scheduled to meet in November 2008 to consider the remedial approach proposed by the Remedial Project Manager (RPM) for EPA Region 5. The estimated remediation costs for the site range between $49.7 million and $137.5 million, including costs set forth in the revised feasibility study, as well as estimates for WDNR past oversight costs, outside legal and consultant costs and work plan costs.

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In addition to potential liability for remediation, NSP-Wisconsin may also have liability for natural resource damages (NRD) at the Ashland site. NSP-Wisconsin has indicated to the relevant natural resource trustees its interest in engaging in discussions concerning the assessment of natural resources injuries and in proposing various restoration projects in an effort to fully and finally resolve all NRD claims. NSP-Wisconsin is not able to accurately quantify its potential exposure for NRD at the site, but has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility, NSP-Wisconsin s liability for the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable. NSP-Wisconsin has recorded a liability of $65.9 million based on management s best estimate of remediation costs.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for MGP-related environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

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

In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional clean-up costs at the Fort Collins MGP site spent through September 2006, plus unrecovered amounts previously authorized from the last rate case, which amounted to $10.8 million to be amortized over four years. In June 2007, PSCo entered into a settlement agreement that included recovery of the full $10.8 million, but with a five-year amortization period. The CPUC approved the agreement on June 18, 2007. The total amount to be recovered from customers is $13.1 million. Estimated future project costs, based upon an assumed 30-year system operating life, including EPA oversight costs, are approximately $2.8 million. This reflects a reduction in estimated EPA oversight costs over the life of the project, based upon the most recent EPA oversight billing.

In April 2005, PSCo brought a contribution action against Schrader and related parties (collectively Schrader) alleging Schrader released hazardous substances into the environment and these releases caused MGP byproducts to migrate to the Cache la Poudre River, thereby substantially increasing the scope and cost of remediation. PSCo requested damages, including a portion of the costs PSCo incurred, to investigate and remove contaminated sediments from the Cache la Poudre River. PSCo and Schrader have reached an agreement in principle and are in the process of finalizing a settlement agreement. Net proceeds from the settlement will be credited to ratepayers.

Third Party and Other Environmental Site Remediation

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation.

See additional discussion of asset retirement obligations in Note 15 of the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

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Other Environmental Requirements

Clean Air Interstate Rule (CAIR) In March 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The objective of CAIR was 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. In July 2008, a three-judge panel of the D.C. Circuit Court of Appeals vacated CAIR and remanded the rule to EPA. The EPA subsequently requested a rehearing *en banc*, or by the full court. The D.C. Circuit Court of Appeals has yet to rule on the EPA s petition for rehearing.

Clean Air Mercury Rule (CAMR) In March 2005, the EPA issued the CAMR, which regulated mercury emissions from power plants. In February 2008, the D.C. Circuit Court of Appeals vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. Costs to comply with the Minnesota Mercury Emissions Reduction Act of 2006 are discussed below.

In Colorado, the Air Quality Control Commission (AQCC) passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and all other Colorado units by 2014. Xcel Energy is in the process of installing mercury monitors on five Colorado units at an estimated aggregate cost of approximately $1.9 million. Xcel Energy is evaluating the emission controls required to meet the state rule and is currently unable to provide a capital cost estimate.

Minnesota Mercury Legislation In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For Xcel Energy, the Act covers units at the A. S. King and Sherco generating facilities. Under the Act, Xcel Energy is operating and maintaining continuous mercury emission monitoring systems. The information obtained will be used to establish a baseline from which to measure mercury emission reductions.

On Dec. 21, 2007, Xcel Energy filed mercury emission reduction plans for two dry scrubbed units, Sherco Unit 3 and King, as well as a comprehensive emissions reduction and capacity upgrade proposal for Sherco Units 1 and 2 (wet scrubbed units). A revised specific mercury reduction proposals for these units will be filed by Dec. 31, 2009 as required by the legislation. The Minnesota Pollution Control Agency (MPCA) has reviewed and recommended approval of the Sherco Unit 3 and King mercury emission reduction plans, which are currently being reviewed by the MPUC. Current plans are to install a sorbent injection system at both King and Sherco Unit 3 and use a brominated powered activated carbon as the sorbent. Implementation would occur by Dec. 31, 2009 at Sherco Unit 3 and by Dec. 31, 2010 for King. The expected total capital costs for both sorbent injection systems is $9.0 million. The sorbent is currently estimated to cost $3.8 million annually for King and $5.5 million for Sherco Unit 3.

Utilities subject to the Act may also submit plans to address non-mercury pollutants subject to federal and state statutes and regulations, which became effective after Dec. 31, 2004. Cost recovery provisions of the Act also apply to these other environmental initiatives. In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs that are expected to be recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. On August 26, 2008 NSP-Minnesota filed a request with the MPUC to increase the deferral to $19.4 million as NSP-Minnesota anticipated exceeding the authorized deferral amount in September 2008.

Voluntary Capacity Upgrade and Emissions Reduction Filing In December 2007, NSP-Minnesota filed a plan with the Minnesota Pollution Control Agency (MPCA) and MPUC for reducing mercury emissions by up to 90 percent at the Sherco unit 3 and A. S. King plants. Estimated project costs amount to approximately $9.1 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco units 1 and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1

billion. The filing also contains alternatives for the MPUC to consider to add additional capacity and to achieve even lower emissions. If selected, these alternatives could range from $90.8 to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota s investments are subject to MPUC approval of a cost recovery mechanism. The MPCA has issued its assessment that the Sherco unit 3 and A. S. King plans are appropriate. Given changes in circumstance related to technology, the economy and regulatory requirements, however, NSP-Minnesota is currently reassessing the emissions reduction project at Sherco units 1 and 2.

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Regional Haze Rules In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements.

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. In May 2006, the Colorado AQCC promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of the BART alternatives will cost approximately $201 million in capital costs, which includes approximately $59 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. Colorado s state implementation plan has been submitted to EPA for approval. In early 2008, the Colorado Air Pollution Control Division (CAPCD) initiated a stakeholder process to establish reasonable progress goals for Colorado s Class I areas. To meet these goals, more controls may be required from certain sources, which may or may not include those sources previously controlled under BART. The reasonable progress stakeholder process has been placed on hold by the CAPCD due to limited resources and is expected to resume in early 2009.

NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. In light of the D.C. Circuit Court of Appeals decision vacating CAIR, the MPCA has requested that companies with BART-eligible units inform the MPCA whether the company will rely on the initial BART determination submittal or if they intend to submit a revised analysis. NSP-Minnesota will submit a revised BART alternatives analysis, primarily to account for cost changes that have occurred since the original submittal.

Federal Clean Water Act The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit challenging the phase II rulemaking. In January 2007, the court issued its decision and remanded virtually every aspect of the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state s best professional judgment until the EPA is able to fully respond to the court-ordered remand. As a result, the rule s compliance requirements and associated deadlines are currently unknown. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved. In April 2008, the U.S. Supreme Court granted limited review of the Second Circuit s opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. A decision is not expected until 2009.

The MPCA exercised its authority under best professional judgment to require Black Dog Generating Station in its recently renewed wastewater discharge permit to create a plan by April 2010 to reduce the plant intake s impact on aquatic wildlife. NSP-Minnesota has begun initial discussions with the local community and regulatory agencies about the potential options to address this concern.

Maddox Station Groundwater The New Mexico Environment Department (NMED) is requiring wastewater activity at Maddox Station to be permitted. SPS is developing the engineering wastewater management facilities and submitted the permit application in July 2008. The estimated cost of the project is $1.8 million with an anticipated completion date in June 2009.

New York Office of the Attorney General Subpoena In September 2007, the Office of the New York Attorney General (NYAG) issued a subpoena pursuant to the Martin Act, a New York statute, to Xcel Energy. The subpoena sought 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 asserted that the increase in carbon dioxide (CO_2) emissions upon completion of Comanche 3 (a coal-fired unit), in combination with Xcel Energy s other coal-fired plants, will subject Xcel to increased financial, regulatory and litigation risks which need to be disclosed to shareholders. Xcel Energy believes it has fully disclosed these risks, to the extent they can be ascertained, and such disclosures belie the concerns expressed by the NYAG. On Aug. 26, 2008, Xcel Energy and the NYAG reached a settlement regarding this matter whereby Xcel Energy, without admitting or denying any violation of law or wrongdoing, agreed to voluntarily expand and/or continue to provide a discussion of climate change and possible attendant risks in its 10-K filings with the SEC. Xcel Energy believes that the settlement will not have a material effect on the consolidated financial statements.

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PSCo Notice of Violation In July 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche and Pawnee plants in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

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

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy s financial position and results of operations.

Gas Trading Litigation

e prime was a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Twelve lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin in one instance), alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP-Wisconsin deny these allegations and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas-trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the United States District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned *Texas-Ohio Energy vs. CenterPoint Energy.* The other eleven cases arising out of the same or similar set of facts are captioned *Fairhaven Power Company vs. EnCana Corporation et al; Ableman Art Glass vs. EnCana Corporation et al; Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. et al; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al; Learjet, Inc. vs. e prime and Xcel Energy Inc et al; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. et al; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al and Hartford Regional Medical Center vs. e prime, Xcel Energy et al*. Many of these cases involve multiple defendants and have been transferred to Judge Phillip Pro of the United States District Court in Nevada, who is the judge assigned to the western area wholesale natural gas antitrust litigation. An exception is the *Missouri Public Service Commission* case, which was remanded to Missouri state court in November 2007.

In April 2005, Judge Pro granted defendants motion to dismiss in *Texas Ohio Energy* based upon the filed rate doctrine. Based upon this same legal doctrine, Judge Pro subsequently granted defendants motion to dismiss in *Fairhaven Power Company, Ableman Art Glass and Utility Savings and Refund Services*. Plaintiffs subsequently appealed these dismissals to the Ninth Circuit Court of Appeals. In September 2007, the Ninth Circuit Court of Appeals reversed the dismissal and remanded the lawsuits to Judge Pro for consideration of whether any of plaintiffs claims are based upon retail rates not directly barred by the filed rate doctrine. e prime and some other defendants were dismissed from the *Breckenridge* lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

All of the gas trading lawsuits are in the early procedural stages of litigation. No trial dates have been set for any of these lawsuits; however, defendants motions to dismiss are pending in the *Missouri Public Service Commission* matter, and defendants summary judgment motions are pending in the *Learjet and J.P. Morgan* matters. An Early Neutral Evaluation session took place on July 16, 2008 on the *Abelman, Ever Bloom, Fairhaven, Texas-Ohio*, and *Utility Savings* cases, but a settlement was not reached. Trial for all cases venued in Nevada will likely be set for late 2009 or early 2010.

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Cabin Creek Hydro Generating Station Accident

In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo s Cabin Creek Hydro Generating Station near Georgetown, Colo. This work was being performed as part of a corrosion prevention effort. A fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U.S. Chemical Safety Board and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008 the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17, 2008. The Court ordered this proceeding stayed until March 3, 2009 and indicated an extension of the stay is possible. A lawsuit has been filed in Denver District Court on behalf of four of the deceased workers and four of the injured workers. PSCo and Xcel Energy Inc. are named as defendants, along with RPI Coatings, its parent company, Prezioso, and two other contractors who performed work in connection with the relining project at Cabin Creek. A second lawsuit (Ledbetter et. al vs. Xcel Energy et. al) has also been filed by and on behalf of three employees allegedly injured in the accident. Neither complaint filed in court has been served upon Xcel Energy or PSCo. Xcel Energy and PSCo intend to vigorously defend themselves against the claims asserted in the lawsuits.

Environmental Litigation

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

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

capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal theories, including negligence and public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. In September 2007, plaintiffs filed a notice of appeal to the Fifth Circuit Court of Appeals. Oral arguments were presented to the Court of Appeals on Aug. 6, 2008. On Sept. 26, 2008, the Court of Appeals notified the parties that this matter was set for re-argument on Nov. 3, 2008. No explanation was given for the decision.

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other oil, gas and coal companies. The suit was brought on behalf of approximately 400 native Alaskans, the Inupiat Eskimo, who claim that Defendants emission of CO_2 and other greenhouse gases (GHG) contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence, the entire village must be relocated at a cost of between $95 million and $400 million. Plaintiffs assert a nuisance claim under federal and state common law, as well as a claim asserting concert of action in which defendants are alleged to have engaged in tortious acts in concert with each other. Xcel Energy was not named in the civil conspiracy claim. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008.

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

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Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy In June 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota s distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. After its motion to dismiss plaintiffs claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007, the court granted NSP- Minnesota s motion for certification, and the parties have filed briefs on appeal. Oral arguments took place on Sept. 11, 2008. Mediation took place on Oct. 14, 2008, but the matter was not resolved.

Qwest vs. Xcel Energy Inc. In June 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Denver state court. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. Pursuant to this agreement, Qwest asserted PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. In May 2006, PSCo filed a counterclaim against Qwest asserting Qwest had a duty to PSCo and an obligation under the contract to maintain its poles in a safe and serviceable condition. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. On June 16, 2008, Qwest filed its appellate brief. After the matter is fully briefed by the parties, oral arguments will be scheduled.

Hoffman vs. Northern States Power Company In March 2006, a purported class action complaint was filed in Minnesota state court, on behalf of NSP-Minnesota s residential customers in Minnesota, North Dakota and South Dakota for alleged breach of a contractual obligation to maintain and inspect the points of connection between NSP-Minnesota s wires and customers homes within the meter box. Plaintiffs claim NSP-Minnesota s alleged breach results in an increased risk of fire and is in violation of tariffs on file with the MPUC. Plaintiffs seek injunctive relief and damages in an amount equal to the value of inspections plaintiffs claim NSP-Minnesota was required to perform over the past six years. In August 2006, NSP-Minnesota filed a motion for dismissal on the pleadings. In November 2006, the court issued an order denying NSP-Minnesota s motion, but later, pursuant to a motion by NSP-Minnesota, certified the issues raised in NSP-Minnesota s original motion for appeal as important and doubtful, and NSP-Minnesota filed an appeal with the Minnesota Court of Appeals. In January 2008, the Minnesota Court of Appeals determined the plaintiffs claims are barred by the filed rate doctrine and remanded the case to the district court for dismissal. Plaintiffs have petitioned the Minnesota Supreme Court for discretionary review, and in April 2008, the court granted the petition. The matter has been briefed by both parties. Oral argument has been set for Nov. 4, 2008.

MGP Insurance Coverage Litigation In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in

Ashland, Chippewa Falls, Eau Claire and LaCrosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin s insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state circuit court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

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

In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of eleven insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Court of Appeals for Minnesota challenging the dismissal of these carriers. In November 2007, Ranger Insurance Company (Ranger) and TIG Insurance Company (TIG) filed a motion to dismiss NSP-Wisconsin s appeal, asserting that NSP-Wisconsin s failure to serve Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company (Harbor), requires dismissal of NSP-Wisconsin s appeal. In February 2008, the Court of Appeals issued an order deferring a decision on the procedural motion filed by Harbor and TIG and referring the motion to the panel assigned to consider the merits of the appeal.

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

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

Nuclear Waste Disposal Litigation In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages for the U.S. Department of Energy s (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE s motion for reconsideration. In February 2008, the DOE filed an appeal to the U.S. Court of Appeals for the Federal Circuit, and NSP-Minnesota cross-appealed on the cost of capital issue. In April 2008, the DOE asked the appellate court to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court granted the request. Results of the judgment will not be recorded in earnings until the appeal and regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE s continuing failure to abide by the terms of the contract. This lawsuit claims damages for the period Jan. 1, 2005 through June 30, 2007, which includes costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel. The amount of such damages is expected to exceed $40 million. In January 2008, the court granted the DOE s motion to stay, subject to reevaluation after a decision has been filed in any one of the five pending appeals of nuclear waste storage cases.

Mallon vs. Xcel Energy Inc. In July 2007, Theodore Mallon and TransFinancial Corporation filed a declaratory judgment action against Xcel Energy in U. S. District Court in Colorado (Mallon Federal Action). In this lawsuit, plaintiffs seek a determination that Xcel Energy is not entitled to assert claims against plaintiffs related to the 1984 and 1985 sale of COLI to PSCo, a predecessor of Xcel Energy. In August 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in Colorado state court against Mallon and TransFinancial Corporation (Mallon State Action). In the Mallon State Action, Xcel Energy, PSCo and PSRI seek damages against Mallon and TransFinancial for, among other things, breach of contract and breach of fiduciary duties associated with the sale of the COLI policies. In August 2007, Xcel Energy also filed a motion to stay or, in the alternative, to dismiss the Mallon Federal Action. In September 2007, a motion to stay the Mallon State Court action was subsequently filed by Mallon and TransFinancial. In November 2007, the U.S. District Court in Colorado dismissed the complaint in the Mallon Federal Action and Mallon and TransFinancial subsequently withdrew their motion to stay the Mallon State Court Action. In May 2008, Xcel Energy, PSCo and PSRI filed a second amended complaint that, among other things, adds Provident Life & Accident Insurance Company (Provident) as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. On June 23, 2008, Provident filed a motion to dismiss the complaint. Xcel Energy, PSCo and PSRI filed a brief in opposition to the motion on July 28, 2008. Oral arguments were presented to the court on Sept. 19, 2008. On Oct. 22, 2008, Judge Morris Sandstead, Jr. granted Provident s motion in part, but denied the motion with respect to a majority of the core causes asserted by PSCo, Xcel Energy Inc. and PSRI Investments.

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Fru-Con Construction Corporation vs. Utility Engineering (UE) et al. In March 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con s complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE s motion to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

Lamb County Electric Cooperative (LCEC) In 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging SPS was unlawfully providing service to oil field customers in LCEC s certificated area. In May 2003, the PUCT issued an order denying LCEC s petition based on its determination that SPS in 1976 was granted a certificate to serve the disputed customers. LCEC appealed the decision to the District Court in Travis County, Texas. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the District Court s decision to the Court of Appeals for the Third Supreme Judicial District of the state of Texas. This appeal is currently pending.

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

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In 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination of the legality of SPS providing electric service to the disputed customers. The PUCT order from May 2003, which found SPS was legally serving the disputed customers, collaterally determines the issue of liability contrary to LCEC s position in the suit. An adverse ruling on the appeal of May 2003 PUCT order could result in a different determination of the legality of SPS service to the disputed customers.

8. Short-Term Borrowings and Other Financing Instruments

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

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Short-Term Borrowings

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Commercial Paper At Sept. 30, 2008 and Dec. 31, 2007, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $264.0 million and $1,088.6 million, respectively. The weighted average interest rates at Sept. 30, 2008 and Dec. 31, 2007 were 3.19 percent and 5.57 percent, respectively.

Guarantees

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On Sept. 30, 2008 and Dec. 31, 2007, Xcel Energy had issued guarantees of up to $64.9 million and $75.2 million, respectively, 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, 2008 and Dec. 31, 2007, was approximately $27.9 million and $31.6 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

9. Long-Term Borrowings and Other Financing Instruments

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Comer vs. Xcel Energy Inc. et al. In April 2006, Xcel Energy received notice of a purported class action lawsuit file

Junior Subordinated Notes

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

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

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

First Mortgage Bonds

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

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On Aug. 13, 2008, PSCo issued $300 million of 5.80 percent first mortgage bonds, series due Aug. 1, 2018 and $300 million of 6.50 percent first mortgage bonds, series due Aug. 1, 2038. PSCo added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $300 million of 4.375 percent first mortgage bonds due Oct. 1, 2008.

On Sept. 10, 2008, NSP-Wisconsin issued $200 million of 6.375 percent first mortgage bonds, series due Sept. 1, 2038. NSP-Wisconsin added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of such net proceeds to fund the payment at maturity of $80 million of 7.64 percent senior notes due Oct. 1, 2008. The balance of the net proceeds will be used for the repayment of short-term debt (including notes payable to affiliates) and general corporate purposes that may include the refinancing of higher-interest rate long-term debt and general working capital.

10. Derivative Instruments

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

Cash Flow Hedges

Commodity Cash Flow Hedges Xcel Energy s utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. 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 and fuel for fleet vehicles. These derivative instruments are designated as cash flow hedges for accounting purposes. At Sept. 30, 2008, Xcel Energy had various commodity-related contracts designated as cash flow hedges extending through December 2010. Changes in the fair value of cash flow hedges are recorded in other comprehensive income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place.

At Sept. 30, 2008, Xcel Energy had $3.5 million of net losses in accumulated other comprehensive income related to commodity cash flow hedge contracts; $1.7 million is expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Interest Rate Cash Flow Hedges Xcel Energy and its subsidiaries enter into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

At Sept. 30, 2008, Xcel Energy had $0.2 million of net losses in accumulated other comprehensive income related to interest rate derivatives that are expected to be recognized in earnings during the next 12 months.

The following table shows the major components of the derivative instruments valuation in the consolidated balance sheets at Sept. 30 and Dec. 31:

	Sept. 30, 2008		Dec. 31, 2007	
(Thousands of Dollars)	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation -Liabilities**	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation -Liabilities**
Long term purchased power agreements	$ 387,714	$ 360,823	$ 426,774	$ 401,313
Electric and natural gas trading and hedging instruments	104,996	98,315	51,106	21,694
Interest rate hedging instruments		6,052	535	20,223
Total	$ 492,710	$ 465,190	$ 478,415	$ 443,230

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

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The impact of qualifying cash flow hedges on Xcel Energy s accumulated other comprehensive income, included in the consolidated statements of common stockholders equity and comprehensive income, is detailed in the following table:

(Thousands of Dollars)	Three months ended Sept. 30, 2008		2007	
Accumulated other comprehensive (loss) income related to cash flow hedges at July 1	$	(6,134)	$	8,330
After-tax net unrealized losses related to derivatives accounted for as hedges		(2,589)		(1,954)
After-tax net realized losses (gains) on derivative transactions reclassified into earnings		67		(271)
Accumulated other comprehensive (loss) income related to cash flow hedges at Sept. 30	$	(8,656)	$	6,105

(Thousands of Dollars)	Nine months ended Sept. 30, 2008		2007	
Accumulated other comprehensive (loss) income related to cash flow hedges at Jan. 1	$	(1,416)	$	2,196
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges		(7,347)		4,637
After-tax net realized losses (gains) on derivative transactions reclassified into earnings		107		(728)
Accumulated other comprehensive (loss) income related to cash flow hedges at Sept. 30	$	(8,656)	$	6,105

11. Fair Value Measurements

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

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

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

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

The following table presents, for each of these hierarchy levels, Xcel Energy s assets and liabilities that are measured at fair value on a recurring basis as of Sept. 30, 2008:

(Thousands of Dollars)	Level 1	Level 2	Level 3	Counterparty Netting (a)	Net Balance
Assets					
Cash equivalents	$	$ 10,000	$	$	$ 10,000
Nuclear decommissioning fund	597,311	475,476	113,954		1,186,741
Commodity derivatives	472	17,065	93,520	(6,061)	104,996
Total	$ 597,783	$ 502,541	$ 207,474	$ (6,061)	$ 1,301,737
Liabilities					
Commodity derivatives	$ 3,951	$ 36,684	$ 65,657	$ (7,977)	$ 98,315
Interest rate derivatives		6,052			6,052
Total	$ 3,951	$ 42,736	$ 65,657	$ (7,977)	$ 104,367

(a) FASB Interpretation No. 39 *Offsetting of Amounts Relating to Certain Contracts*, as amended by FASB Staff Position FIN 39-1 *Amendment of FASB Interpretation No. 39*, permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

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The following tables present the changes in Level 3 recurring fair value measurements for the three and nine months ended Sept. 30, 2008:

(Thousands of Dollars)		Commodity Derivatives, Net		Nuclear Decommissioning Fund
Balance, July 1, 2008	$	24,149	$	109,416
Purchases, issuances, and settlements, net		(2,960)		9,110
Transfers out of level 3		(1,466)		
Gains recognized in earnings		2,382		
Gains (losses) recognized as regulatory assets and liabilities		5,758		(4,572)
Balance, Sept. 30, 2008	$	27,863	$	113,954

(Thousands of Dollars)		Commodity Derivatives, Net		Nuclear Decommissioning Fund
Balance, Jan. 1, 2008	$	19,466	$	108,656
Purchases, issuances, and settlements, net		(10,031)		12,760
Transfers out of level 3		(1,414)		
Losses recognized in earnings		(3,884)		
Gains (losses) recognized as regulatory assets and liabilities		23,726		(7,462)
Balance, Sept. 30, 2008	$	27,863	$	113,954

Gains and losses on Level 3 commodity derivatives recognized in earnings for the three and nine months ended Sept. 30, 2008, include $1.2 million and $4.7 million, respectively, of net unrealized gains relating to commodity derivatives held at Sept. 30, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric utility revenues. Realized and unrealized gains and losses on short-term wholesale activities reflect the impact of regulatory recovery and are deferred as regulatory assets and liabilities. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

12. Detail of Interest and Other Income, Net

Interest and other income (expense), net of nonoperating expenses, for the three and nine months ended Sept. 30, 2008, consisted of the following:

	Three months ended Sept. 30,				Nine months ended Sept. 30,			
(Thousands of Dollars)		2008		2007		2008		2007
Interest income	$	9,854	$	6,436	$	22,244	$	15,883
Equity income in unconsolidated affiliates		554		616		1,835		2,800
Other nonoperating income		902		1,680		4,242		2,867
Minority interest income		244		225		510		472
Insurance policy income (expense)		(1,264)		(5,955)		274		(18,852)
Total interest and other income, net	$	10,290	$	3,002	$	29,105	$	3,170

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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, 2008					
Operating revenues from external customers	$ 2,576,467	$ 258,961	$ 16,252	$	$ 2,851,680
Intersegment revenues	225	1,208		(1,433)	
Total revenues	$ 2,576,692	$ 260,169	$ 16,252	$ (1,433)	$ 2,851,680
Income (loss) from continuing operations	$ 223,464	$ 3,960	$ 7,817	$ (12,546)	$ 222,695
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	$ 9,175	$ (16,284)	$ 254,720

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Nine months ended Sept. 30, 2008					
Operating revenues from external customers	$ 6,704,164	$ 1,736,701	$ 54,718	$	$ 8,495,583
Intersegment revenues	767	5,831		(6,598)	
Total revenues	$ 6,704,931	$ 1,742,532	$ 54,718	$ (6,598)	$ 8,495,583
Income (loss) from continuing operations	$ 423,310	$ 83,398	$ 23,423	$ (47,969)	$ 482,162
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	$ (33,640)	$ (49,056)	$ 440,929

14. Common Stock and Equivalents

On Sept. 15, 2008, Xcel Energy issued 15,000,000 shares of common stock to underwriters at a price of $20.10 per share. The shares were re-offered to the public at a price of $20.20 per share plus a commission of $0.05 per share from the purchasers. On

Sept. 18, 2008, Xcel Energy issued 2,250,000 shares of common stock pursuant to the underwriters exercise in full of their over-allotment. The proceeds from these offerings were used to repay commercial paper.

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

For the three months ended Sept. 30, 2008 and 2007, Xcel Energy had approximately 8.0 million and 9.5 million stock options that were antidilutive and excluded from the dilutive earnings per share calculation, respectively. For the nine months ended Sept. 30, 2008 and 2007, Xcel Energy had approximately 8.0 million and 10.3 million stock options that were antidilutive and excluded from the dilutive earnings per share calculation, respectively.

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The dilutive impact of common stock equivalents affected earnings per share as follows for the three and nine months ending Sept. 30, 2008 and 2007:

	Three months ended Sept. 30, 2008			Three months ended Sept. 30, 2007		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 222,695			$ 254,720		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	221,635	434,131	$ 0.51	253,660	419,822	$ 0.60
Effect of dilutive securities:						
Convertible debt	801	4,663		2,190	13,094	
401(k) equity awards		583			435	
Stock options		20			36	
Diluted earnings per share:						
Earnings available to common shareholders and assumed conversions	$ 222,436	439,397	$ 0.51	$ 255,850	433,387	$ 0.59

	Nine months ended Sept. 30, 2008			Nine months ended Sept. 30, 2007		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 482,162			$ 440,929		
Less: Dividend requirements on preferred stock	(3,180)			(3,180)		
Basic earnings per share:						
Earnings available to common shareholders	478,982	431,511	$ 1.11	437,749	413,555	$ 1.06
Effect of dilutive securities:						
Convertible debt	2,382	4,663		8,975	18,726	
401(k) equity awards		516			441	
Stock options		26			89	
Diluted earnings per share:						
Earnings available to common shareholders and assumed conversions	$ 481,364	436,716	$ 1.10	$ 446,724	432,811	$ 1.03

15. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost (Credit)

	Three months ended Sept. 30,			
	2008 (1)	2007 (1)	2008	2007
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 15,851	$ 15,520	$ 1,338	$ 1,453
Interest cost	42,630	41,313	12,720	12,619
Expected return on plan assets	(68,584)	(66,208)	(7,963)	(7,600)
Amortization of transition obligation			3,644	3,644
Amortization of prior service cost (credit)	5,166	6,487	(544)	(545)
Amortization of net loss	3,185	4,211	2,875	3,550

Net periodic benefit (credit) cost		(1,752)		1,323		12,070		13,121
Credits not recognized due to the effects of regulation		2,258		2,787				
Additional cost recognized due to the effects of regulation						972		972
Net benefit cost recognized for financial reporting	$	506	$	4,110	$	13,042	$	14,093

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

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(Thousands of Dollars)	Nine months ended Sept. 30, 2008 (1)	2007 (1)	2008	2007
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$ 47,553	$ 46,560	$ 4,013	$ 4,359
Interest cost	127,890	123,939	38,160	37,857
Expected return on plan assets	(205,753)	(198,624)	(23,888)	(22,800)
Amortization of transition obligation			10,932	10,932
Amortization of prior service cost (credit)	15,498	19,461	(1,632)	(1,635)
Amortization of net loss	9,555	12,633	8,624	10,650
Net periodic benefit (credit) cost	(5,257)	3,969	36,209	39,363
Credits not recognized due to the effects of regulation	6,775	8,361		
Additional cost recognized due to the effects of regulation			2,918	2,918
Net benefit cost recognized for financial reporting	$ 1,518	$ 12,330	$ 39,127	$ 42,281

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

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

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

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate, believe, estimate, expect, intend, may, objective, outlook, plan, project, possible, pote expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit and its impact on capital expenditures and the ability of Xcel Energy and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions of accounting regulatory bodies; the items described under Factors Affecting Results of Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A of Xcel Energy s Form 10-K for the year ended Dec. 31, 2007, and Exhibit 99.01 to this report on Form 10-Q for the quarter ended Sept. 30, 2008.

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RESULTS OF OPERATIONS

Summary of Financial Results

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

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

Contribution to Earnings (Millions of Dollars)	Three months ended Sept. 30, 2008	Three months ended Sept. 30, 2007	Nine months ended Sept. 30, 2008	Nine months ended Sept. 30, 2007
GAAP income (loss)				
Regulated electric utility income continuing operations	$ 223.4	$ 260.4	$ 423.3	$ 456.4
Regulated natural gas utility income continuing operations	4.0	1.4	83.4	67.2
Other utility results	7.3	6.8	23.3	(37.1)
Utility income continuing operations	234.7	268.6	530.0	486.5
Holding company costs and other results	(12.0)	(13.9)	(47.8)	(45.6)
Income continuing operations	222.7	254.7	482.2	440.9
Income (loss) discontinued operations	0.1	0.1	(0.7)	2.4
Total GAAP income	$ 222.8	$ 254.8	$ 481.5	$ 443.3

	Three months ended Sept. 30, 2008	Three months ended Sept. 30, 2007	Nine months ended Sept. 30, 2008	Nine months ended Sept. 30, 2007
GAAP earnings per share contribution				
Regulated electric utility continuing operations	$ 0.51	$ 0.60	$ 0.97	$ 1.05
Regulated natural gas utility continuing operations	0.01		0.19	0.16
Other utility results	0.02	0.02	0.05	(0.09)
Utility earnings per share continuing operations	0.54	0.62	1.21	1.12
Holding company costs and other results	(0.03)	(0.03)	(0.11)	(0.09)
Earnings per share continuing operations	0.51	0.59	1.10	1.03
Earnings per share discontinued operations				0.01
Total GAAP earnings per share diluted	$ 0.51	$ 0.59	$ 1.10	$ 1.04

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

Increase (decrease)	Three months ended Sept. 30, 2008 vs. 2007	Nine months ended Sept. 30, 2008 vs. 2007
2007 GAAP earnings per share	**$ 0.59**	**$ 1.04**
Earnings per share discontinued operations		(0.01)
2007 GAAP earnings per share-continuing operations	0.59	1.03
PSRI/COLI IRS settlement	(0.01)	0.09
2007 ongoing earnings per share	**0.58**	**1.12**
Components of change 2008 vs. 2007		
Higher (lower) base electric utility margins	(0.04)	0.02
Higher depreciation and amortization	(0.03)	(0.03)
Lower wholesale and commodity trading margins	(0.01)	(0.01)
Higher allowance for funds used during construction-equity	0.02	0.05
Lower (higher) conservation and demand-side management program expenses	0.01	(0.02)
Higher natural gas margins	0.01	0.06
Higher operating and maintenance expense		(0.06)
Higher financing costs		(0.02)
Other, including income taxes	(0.03)	(0.01)
Net change in earnings per share	**(0.07)**	**(0.02)**
2008 GAAP earnings per share	**$ 0.51**	**$ 1.10**

During 2007, Xcel Energy resolved a dispute with the IRS regarding its COLI program. Excluding the impact of the COLI program, Xcel Energy s ongoing third quarter 2008 earnings were $223 million, or $0.51 per share, compared with third quarter 2007 ongoing earnings of $249 million, or $0.58 per share. The following tables provide a reconciliation of GAAP earnings and earnings per share to ongoing earnings and ongoing earnings per share for 2008 and 2007.

(Millions of Dollars)	Three months ended Sept. 30, 2008	Three months ended Sept. 30, 2007	Nine months ended Sept. 30, 2008	Nine months ended Sept. 30, 2007
Ongoing earnings	$ 223.3	$ 249.2	$ 482.5	$ 480.1
PSRI/COLI IRS settlement	(0.6)	5.5	(0.3)	(39.2)
Total continuing operations	222.7	254.7	482.2	440.9
Discontinued operations	0.1	0.1	(0.7)	2.4
Total GAAP earnings	$ 222.8	$ 254.8	$ 481.5	$ 443.3

	Three months ended Sept. 30, 2008	Three months ended Sept. 30, 2007	Nine months ended Sept. 30, 2008	Nine months ended Sept. 30, 2007
Ongoing earnings	$ 0.51	$ 0.58	$ 1.11	$ 1.12
PSRI/COLI IRS settlement		0.01		(0.09)
Total GAAP earnings per share-continuing operations	$ 0.51	$ 0.59	$ 1.11	$ 1.03
Discontinued operations			(0.01)	0.01
Total GAAP earnings per share	$ 0.51	$ 0.59	$ 1.10	$ 1.04

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

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Utility Results

Ongoing and GAAP earnings for the third quarter of 2008 were lower than the third quarter of last year primarily due to lower electric margins and higher depreciation and amortization expenses. Lower electric margins were largely due to the negative impact of cooler temperatures in the third quarter of 2008 as well as an overall decline in residential electric customer sales growth. The increase in depreciation expense was primarily due to the approval of a NSP-Minnesota remaining lives depreciation filing in the third quarter of 2007 related to the life extension of the Monticello nuclear plan, which served to reduced depreciation expense in that period by approximately $31 million.

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,		
	2008 vs. Normal	**2007 vs. Normal**	**2008 vs. 2007**	**2008 vs. Normal**	**2007 vs. Normal**	**2008 vs. 2007**
Retail electric	$ (0.01)	$ 0.04	$ (0.05)	$ (0.01)	$ 0.06	$ (0.07)
Firm natural gas				0.01		0.01
Total	$ (0.01)	$ 0.04	$ (0.05)	$	$ 0.06	$ (0.06)

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

Seren Innovations Inc., NRG, e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all divested or sold in 2006 or earlier, have activity reflected on Xcel Energy s financial statements. See Note 4 to the consolidated financial statements.

Income Statement Analysis

Electric Utility, Short-Term Wholesale and Commodity Trading Margins

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

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

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

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

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Three months ended Sept. 30, 2008				
Electric utility revenues (excluding commodity trading)	$ 2,527	$ 48	$	$ 2,575
Electric fuel and purchased power-utility	(1,467)	(47)		(1,514)
Commodity trading revenues			51	51
Commodity trading expenses			(50)	(50)
Gross margin before other operating expenses	$ 1,060	$ 1	$ 1	$ 1,062
Margin as a percentage of revenues	41.9%	2.1%	2.0%	40.4%

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(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-utility	(1,041)	(61)		(1,102)
Commodity trading revenues			74	74
Commodity trading expenses			(72)	(72)
Gross margin before other operating expenses	$ 1,088	$ 8	$ 2	$ 1,098
Margin as a percentage of revenues	51.1%	11.6%	2.7%	48.3%

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Nine months ended Sept. 30, 2008				
Electric utility revenues (excluding commodity trading)	$ 6,536	$ 164	$	$ 6,700
Electric fuel and purchased power-utility	(3,722)	(149)		(3,871)
Commodity trading revenues			118	118
Commodity trading expenses			(114)	(114)
Gross margin before other operating expenses	$ 2,814	$ 15	$ 4	$ 2,833
Margin as a percentage of revenues	43.1%	9.1%	3.4%	41.6%
Nine months ended Sept. 30, 2007				
Electric utility revenues (excluding commodity trading)	$ 5,745	$ 184	$	$ 5,929
Electric fuel and purchased power-utility	(2,946)	(167)		(3,113)
Commodity trading revenues			227	227
Commodity trading expenses			(221)	(221)
Gross margin before other operating expenses	$ 2,799	$ 17	$ 6	$ 2,822
Margin as a percentage of revenues	48.7%	9.2%	2.6%	45.8%

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

Base Electric Utility Revenues

(Millions of Dollars)	Three months ended Sept. 30, 2008 vs. 2007	Nine months ended Sept. 30, 2008 vs. 2007
Fuel and purchased power cost recovery	$ 393	$ 692
Retail rate increases (Wisconsin and North Dakota interim)	13	32
Conservation and non-fuel riders	12	32
MERP rider	7	17
Sales growth (excluding weather impact)	2	24
Transmission revenues	2	11
Increased revenues due to leap year (weather normalized impact)		9
Estimated impact of weather	(32)	(48)
Retail customer sales mix	(2)	(11)
Firm wholesale	(7)	(9)
Nuclear refueling outage revenue, subject to refund due to change in recovery method	(17)	(17)
Other	27	59
Total increase in base electric utility revenues	$ 398	$ 791

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Base Electric Utility Margin

(Millions of Dollars)	Three months ended Sept. 30, 2008 vs. 2007	Nine months ended Sept. 30, 2008 vs. 2007
Estimated impact of weather	$ (32)	$ (48)
Nuclear refueling outage revenue, subject to refund due to change in recovery method	(17)	(17)
Firm wholesale	(4)	(2)
Retail customer sales mix	(2)	(11)
Purchased capacity costs	(1)	(5)
Retail rate increases (Wisconsin and North Dakota interim)	13	32
MERP rider	7	17
Conservation and non-fuel riders	4	18
Sales growth (excluding weather impact)	2	24
Increased margin due to leap year (weather normalized impact)		9
Other, including fuel recovery, handling and procurement and net transmission revenue	2	(2)
Total (decrease) increase in base electric utility margin	$ (28)	$ 15

Natural Gas Utility Margins

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

	Three months ended Sept. 30,		Nine months ended Sept. 30,	
(Millions of Dollars)	**2008**	**2007**	**2008**	**2007**
Natural gas utility revenues	$ 259	$ 184	$ 1,737	$ 1,442
Cost of natural gas sold and transported	(156)	(89)	(1,299)	(1,050)
Natural gas utility margin	$ 103	$ 95	$ 438	$ 392

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

Natural Gas Revenues

(Millions of Dollars)	**Three months ended Sept. 30, 2008 vs. 2007**	**Nine months ended Sept. 30, 2008 vs. 2007**
Purchased natural gas adjustment clause recovery	$ 66	$ 247
Base rate changes (Minnesota, Colorado, and Wisconsin)	5	25
Sales growth, excluding weather impact	3	4
Estimated impact of weather	1	8
Conservation revenue	1	4
Transportation	(1)	1
Increased revenues due to leap year (weather normalized impact)		1
Other		5
Total increase in natural gas revenues	$ 75	$ 295

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Natural Gas Margin

(Millions of Dollars)	Three months ended Sept. 30, 2008 vs. 2007	Nine months ended Sept. 30, 2008 vs. 2007
Base rate changes Minnesota, Colorado & Wisconsin	$ 5	$ 25
Sales growth, excluding weather impact	3	4
Estimated impact of weather	1	8
Conservation revenue	1	4
Transportation	(1)	1
Increased margin due to leap year (weather normalized impact)		1
Other	(1)	3
Total increase in natural gas margin	$ 8	$ 46

Non-Fuel Operating Expense and Other Items

Other operating and maintenance expenses Other operating and maintenance expenses for the third quarter of 2008 remained consistent as compared with the same period in 2007. Other operating and maintenance expenses for the first nine months of 2008 increased $39 million, or 3.0 percent, compared with the same period in 2007. For more information see the following table:

(Millions of Dollars)	Three months ended Sept. 30, 2008 vs. 2007	Nine months ended Sept. 30, 2008 vs. 2007
Nuclear outage expenses, net of deferral	$ (14)	$ (18)
Lower employee benefit costs	(12)	(18)
Higher labor costs	9	23
Higher consulting costs	8	15
Higher plant generation costs	5	24
Higher contract labor	3	9
Other, including nuclear plant operation costs	1	4
Total increase in other operating and maintenance expenses	$	$ 39

The following provides an explanation of certain items listed in the table above:

- The decline in nuclear outage expense is due to the MPUC, NDPSC and SDPUC approving the change in accounting from the direct expense method to the deferral and amortization method as appropriate for regulatory accounting purposes effective Jan. 1, 2008.

• The increase in labor costs was attributable to annual wage increases, the insourcing of certain functions, and additional employees to support system growth.

• The higher plant generation costs were primarily attributable to normally scheduled and unplanned maintenance.

• Lower current period and year-to-date employee benefit costs are due to adjustments in our performance based incentive plan.

Depreciation and amortization Depreciation and amortization expense increased by approximately $22.7 million, or 12.2 percent, for the third quarter of 2008, and $19.0 million, or 3.1 percent for the first nine months of 2008, compared with the same periods in 2007. The third quarter increase is primarily due to the MPUC approval of NSP-Minnesota s remaining lives depreciation filing in the third quarter of 2007, extending the life of the Monticello plant by 20 years. This decision was retroactive to the beginning of the year and reduced depreciation expense by approximately $31 million in the third quarter of 2007; however, it did not impact depreciation expense for the first two quarters of 2007. **The year-to-date increase was due to planned system expansion partially offset by a decrease in depreciation expense due to the MPUC approval of two NSP-Minnesota depreciation filings in September 2008.**

Conservation and DSM Conservation and DSM expense decreased approximately $7.1 million, or 20.6 percent for the third quarter of 2008 and increased $16.3 million, or 21.4 percent, for the first nine months of 2008, compared to the same periods in 2007. The higher expense for the first nine months of 2008 is attributable to the ongoing expansion of programs and is designed, in part, to meet regulatory commitments. Conservation and DSM program expenses are generally recovered through rates or rider mechanisms in Xcel Energy s various jurisdictions.

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Interest and other income, net Interest and other income increased by $7.3 million for the third quarter of 2008, and $25.9 million for the first nine months of 2008, compared with the same periods in 2007. The increase is primarily the result of PSRI terminating the COLI program in 2007, which eliminated certain expenses.

Allowance for funds used during construction, equity and debt (AFUDC) AFUDC increased by approximately $8.4 million for the third quarter of 2008, and $24.8 million for the first nine months of 2008 when compared with the same periods in 2007. The increase was due primarily to the construction of Comanche 3 and other construction projects.

Income taxes Income taxes for continuing operations increased by $1 million for the third quarter of 2008, compared with 2007. The effective tax rate for continuing operations was 35.3 percent for the third quarter of 2008, compared with 32.2 percent for the same period in 2007. The higher effective tax rate for third quarter 2008 as compared with 2007 was primarily due to benefits from the COLI policies in the third quarter of 2007. Without these benefits, the effective tax rate for the third quarter of 2007 would have been 34.8 percent.

Income taxes for continuing operations increased by $13 million for the first nine months of 2008, compared with 2007. The increase in income tax expense was primarily due to an increase in pretax income in 2008. The effective tax rate for continuing operations was 34.5 percent for the first nine months of 2008, compared with 35.2 percent for the same period in 2007.

Factors Affecting Results of Continuing Operations

Fuel Supply and Costs

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

Regulation

Summary of Recent Regulatory Developments

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

FERC Tie Line Investigation In October 2007, the FERC Office of Enforcement, Division of Investigations (DOI), commenced a non-public investigation of use of network transmission service across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. Xcel Energy is fully cooperating with the DOI investigation. In July 2008, the DOI issued a preliminary report alleging Xcel Energy violated FERC policies and rules and approved tariffs. The report represents the preliminary conclusions of the DOI and is subject to additional procedures. The report does not constitute a finding by the FERC, which may, among other things, accept, modify or reject any or all of the preliminary conclusions set forth in the report. Xcel Energy disagrees with the preliminary report and has responded to the DOI allegations; Xcel Energy is not able to predict the outcome of the investigation or what, if any, actions the FERC may take. As previously discussed under Item 1A Risk Factors in Xcel Energy s 2007 Annual Report on Form 10-K, the Energy Policy Act of 2005 has increased the FERC s civil penalty authority for violation of FERC statutes, rules and orders. Given the preliminary nature of this matter, Xcel Energy is unable to determine if the resolution of this matter will have a material adverse impact on operations, cash flows or financial condition.

Electric Reliability Standards Compliance The FERC has approved 120 North American Electric Reliability Corporation (NERC) electric reliability standards as mandatory and subject to enforcement under the Energy Act. The FERC has also approved eight Western Electricity Coordinating Council (WECC) regional reliability standards as mandatory. While the ultimate impact of the new regulations and reliability standards cannot be predicted, Xcel Energy is taking actions that are intended to comply with and implement these new regulations and standards as they become effective. The 2008 developments regarding reliability standards include:

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Compliance Audits

The NSP System and PSCo were subject to electric reliability standards compliance audits in first and second quarter 2008, respectively. The Midwest Reliability Organization (MRO) found the NSP System in compliance with all NERC standards audited. In September 2008, the WECC auditors issued a report finding PSCo possibly non-compliant with one of the 54 NERC standards and one of the six WECC standards for which PSCo was audited. The audit report is subject to further WECC procedures.

Compliance with NERC Protective Maintenance Standards

In April 2008, the NSP System, PSCo and SPS each filed self-reports with the MRO, WECC and SPP relating to failure to complete certain generation station battery tests required by NERC protective maintenance standards. As required by NERC procedures, mitigation plans were filed with each of these NERC regional entities. Based on preliminary discussions with the MRO, Xcel Energy expects that penalties will be assessed by the NERC regional entities in conjunction with the self-reports related to incomplete generation station battery tests. The penalties are not expected to be material.

In response to a WECC data request in the PSCo compliance audit, PSCo conducted a comprehensive review of the relay maintenance records for all relay devices on the entire PSCo transmission system. That review found approximately 5.5 percent of the total devices on the PSCo system had not been maintained on the schedule recommended in Xcel Energy s adopted protective maintenance plan. In June 2008, PSCo filed a self-report with WECC regarding the maintenance plan violations. Xcel Energy conducted a similar review of the relay maintenance for the NSP System and SPS system. Those reviews also found a lack of complete maintenance documentation for relays on the NSP System and SPS system. The NSP System and SPS self-reported the NERC standards violations to the MRO and SPP respectively. As required by NERC procedures, PSCo and SPS also filed mitigation plans with the regional entities to correct the testing deficiencies by year-end 2008. A revised self-report and mitigation plan for the NSP System is under development and is expected to be filed with the MRO in fourth quarter 2008.

Compliance with Critical Infrastructure Protection Standards

In September 2008, as a result of a review of its procedures implementing certain NERC critical infrastructure protection standards applicable to control centers effective July 1, 2008, PSCo, the NSP System and SPS filed self-reports disclosing certain deficiencies in requirements applicable to access to critical cyber assets to the WECC, MRO and SPP, respectively. PSCo, the NSP System and SPS filed mitigation plans within 30 days from the date of the self-reports discussing how the deficiencies were corrected.

Except as noted, Xcel Energy is uncertain if the WECC compliance audit of PSCo or the NERC standards violations self-reported in 2008 will result in financial penalties. If so, the penalties are not expected to be material.

Self-Reported 2007 NERC Reliability Standards Violations No Penalties Assessed

In July 2008, FERC accepted findings of the MRO and SPP proposing to impose no enforcement penalties against the NSP System and SPS related to 2007 self-reports of non-compliance with certain NERC reliability standards.

MRO/NERC Compliance Investigation

In March 2008, NSP-Minnesota received notice that the MRO was commencing a compliance investigation of the Sept. 18, 2007 event, when portions of the NSP System briefly islanded from the rest of the Eastern Interconnection, as a result of a series of transmission line outages. Because the event affected more than one region, the NERC took over the investigation. In June 2008, the NERC issued a data request to Xcel Energy for information and in July 2008, Xcel Energy provided responses to these requests. It is expected that the NERC will conduct on-site interviews with Xcel Energy in November 2008 as part of the investigation. The final outcome of the investigation is unknown at this time.

Other Regulatory Matters

NSP-Minnesota

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

- Additional wind generation resources of 2,600 MW, allowing NSP-Minnesota to comply with our RES of 30 percent renewable energy by 2020.

- Increases in DSM of approximately 30 percent energy savings and 50 percent demand savings.

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- Seek license renewals for Prairie Island s two units through 2033 and 2034, respectively, and expand capacity at Prairie Island by 160 MW and Monticello by 71 MW.

- Request approval to make environmental upgrades at Sherco, while expanding capacity by 80 MW. The environmental upgrades would result in a significant reduction in overall SO2, NOx and mercury emissions from the facility.

- Negotiate and seek approval of purchases from Manitoba Hydro Electric Board (Manitoba Hydro) for 375 MW of intermediate and 350 MW of peaking resources beginning in 2015.

- Incremental peaking and intermediate generation needs of 2,300 MWs.

- Carbon emission reductions of 22 percent below 2005 levels by 2020, a six million ton reduction.

In June 2008, intervenors filed comments on this plan. The OES recommended approval, subject to further expansion of DSM goals. Environmental intervenors recommended expanded DSM goals and expressed concerns regarding carbon management with the proposed expansion of certain coal resources. Excelsior Energy recommended inclusion of its proposed project in the plan. The Prairie Island Community expressed health and safety concerns regarding nuclear resources. The Minnesota Chamber of Commerce expressed interest in cost and rate management. NSP-Minnesota filed reply comments in September 2008 providing updated information, including a revised forecast.

NSP-Minnesota Renewable Acquisition Plan In December 2007, NSP-Minnesota filed its renewable acquisition plan outlining its plan for compliance with Minnesota s RES. As part of this plan, NSP-Minnesota issued an RFP for wind power of 500 MW in December 2007. The proposals were received in March 2008, and due diligence and contract negotiations are in progress on selected proposals. Separately, NSP-Minnesota issued a request for proposals for community based wind energy development (CBED) and is negotiating with selected vendors. NSP-Minnesota also requested clarification from the MPUC regarding renewable energy credit ownership regarding certain renewable projects from which NSP-Minnesota purchases renewable energy. The MPUC has requested additional information related to these purchases. MPUC decisions related to these purchases and other mechanics of accounting for renewable energy in 2008 and 2009 will determine the amount of renewable energy or renewable energy credits necessary for NSP-Minnesota to comply with the 2010 milestone for the RES.

Nuclear Plant Power Uprates and Life Extension NSP-Minnesota is pursuing life extensions and capacity increases of all three of its nuclear units that will total approximately 235 MW, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island unit 2 is contingent on replacement of unit 2 s original steam generators, currently planned for replacement during the refueling outage in 2013. Capital investments for life cycle management and power uprate activities through 2007 have totaled approximately $40 million. For the years 2008 through 2015, spending is estimated at $1.1 billion.

NSP-Minnesota has filed two applications for certificates of need related to its nuclear generating facilities to obtain approval for these projects. The first addresses approximately 70 MW of power uprates at the Monticello plant. The MPUC has accepted that filing and set it for hearing, and the evidentiary hearing took place Oct. 6, 2008. The OES was the only intervenor and they recommended approval of the certificate of need. NSP-Minnesota has temporarily withdrawn its Nuclear Regulatory Commission (NRC) application for the Monticello plant extended power uprate and will resubmit the application at a later date, the expectation is sometime in the fourth quarter 2008. Although this delays the extended power uprate process slightly, NSP-Minnesota does not anticipate a substantial delay in the project at this time. The operating life of the Monticello nuclear plant has already been extended through 2030.

The second application addresses both life extension and approximately 160 MW in power uprates at Prairie Island units 1 and 2. The MPUC determined that the application was complete and referred it to an ALJ for contested case hearing at its July 15, 2008 hearing. The Prairie Island Community has indicated its interest in the power uprate portion of the case and has expressed interest in revisiting its 2003 settlement with NSP-Minnesota, in which it agreed that certain concerns it may have regarding Prairie Island life extension would be addressed in the federal relicensing process.

In April 2008, NSP-Minnesota filed an application with the NRC to extend the operating life of its two nuclear reactors at Prairie Island by 20 years. The Prairie Island Indian Community filed contentions to the life extension in August. The Atomic Safety and Licensing Board (Board) is expected to address whether any of the contentions should go to hearing in the fourth quarter. The Board will hold a hearing for oral arguments on Oct. 29, 2008.

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NSP-Minnesota Transmission Certificates of Need In late 2006, NSP-Minnesota filed applications for certificates of need with the MPUC for three transmission lines in southwestern Minnesota. In 2007, the MPUC issued a certificate of need authorizing NSP-Minnesota to construct three new 115 Kilovolt (KV) transmission lines (totaling 35 to 50 miles) in southwestern Minnesota to provide approximately 325 MW of incremental transmission delivery capacity for wind generation. The three projects, including associated substations, are expected to cost $61.1 million. The MPUC order required NSP-Minnesota to file required route permit applications by January 2008 and complete construction by Spring 2009. The route permit applications were filed with the MPUC and SDPUC as required. As of September 2008, the MPUC had granted the three route permits. On Sept. 12, 2008, landowners near one of the approved routes requested rehearing of the route permit for approximately a quarter mile portion of one of the transmission lines and asked the MPUC to order a different route. NSP-Minnesota filed an answer on Sept. 22, 2008. On Oct. 8, 2008, the MPUC voted to provide additional expedited procedures to consider the route alternative proposed by the landowners, but confirmed the route permit for the remainder of the 16 mile line, allowing work to commence. On July 8, 2008, NSP-Minnesota filed a motion requesting the SDPUC to grant an extension of time to issue an order on the South Dakota route permit; absent an extension, the SDPUC could reject the application and require NSP-Minnesota to refile. The SDPUC is expected to act in the fourth quarter of 2008. On April 1, 2008, NSP-Minnesota filed a status report with the MPUC indicating one of the 115 KV transmission lines would be completed by December 2009, but the delay is not expected to materially affect wind generation outlet capacity.

In January 2008, the MPUC voted to grant NSP-Minnesota a certificate of need for the Chisago County, Minnesota project, which would replace an existing 69 KV line with 115 and 161 KV facilities and add a new substation at an estimated cost of $64 million and a route permit for the majority of the proposed line. On June 30, 2008, the MPUC issued an order granting a route permit for the segment of this project. NSP-Minnesota now has obtained all required state regulatory approvals for construction of the Minnesota portion of the transmission line. It is estimated that the project will be placed in service in 2010. The PSCW previously approved construction by NSP-Wisconsin and Dairyland Power Cooperative of related 161 KV facilities in Wisconsin.

As part of CapX 2020, NSP-Minnesota and Great River Energy (on behalf of eight other regional transmission providers) filed a certificate of need application in August 2007, for three 345 KV transmission lines serving Minnesota and parts of surrounding states. The current schedule targets an MPUC order by early 2009. The application stated that the three lines would include construction of approximately 600 miles of new facilities at a cost of $1.3 to $1.6 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 the NSP System. NSP-Minnesota and NSP-Wisconsin cost estimates will be revised after the regulatory process is completed . Evidentiary hearings were completed in September 2008. The OES recommended an increase in capacity for the Fargo, North Dakota project. An environmental coalition supported the projects subject to conditions for wind purchases or commitments for the transmission capacity, while two other intervenors opposed the proposal. The applicants filed rebuttal testimony recommending the modification of all three projects to be constructed as double circuit compatible with the first circuit strung during initial construction and the second circuit strung as needed. Initial briefs are expected to be filed Oct. 24, 2008, and reply briefs on Dec. 5, 2008, and Jan. 12, 2009. NSP-Minnesota expects the ALJ to issue a report and recommendation in February 2009. The MPUC will make a final decision after receipt of the ALJ report.

Also as part of CapX 2020, Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative (on behalf of themselves and NSP-Minnesota and Great River Energy) filed a certificate of need application in March 2008 for a 230 kV transmission line between Bemidji and Grand Rapids, Minnesota. A route application for this project was filed in June 2008. The need application is uncontested; route hearings are expected to begin in the fourth quarter of 2008, and an MPUC decision is anticipated by May 2009. The Bemidji-Grand Rapids line will entail construction of approximately 68 miles of new facilities at a cost of $61 million, with construction to be completed by end of 2011. The application put forth a potential NSP-Minnesota ownership percentage of 26.2 percent.

2008 Minnesota Legislative Session The 2008 Minnesota Legislature considered and adopted several measures related to energy policy and regulation, including:

- Encouragement of Minnesota s participation in the Midwest Governors Association s GHG accord and commissioning of an economic study of the potential impacts of a carbon cap-and-trade program;
- Modifying the existing TCR mechanism to allow for recovery of costs associated with MISO charges for regional transmission expansion;
- Providing for recovery via a rate rider mechanism of certain energy storage projects associated with renewable energy projects; and
- Providing for a streamlined approval process for wind and solar projects needed to comply with Minnesota s RES.

The legislature considered but did not adopt increased taxes on utility property.

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Excelsior Energy On Sept. 24, 2008, the MPUC denied Excelsior Energy s Phase 2 request to approve a power purchase agreement related to its proposed second 600 MW integrated gas combined cycle generating facility. The MPUC also set a May 1, 2009 deadline for Phase 1 of the proceeding in which it had previously ordered negotiations. On Oct. 14, 2008, Excelsior sought rehearing of the MPUC s Sept. 24, 2008 order. Replies are expected to be filed Oct. 24, 2008, and the MPUC is expected to decide whether to grant rehearing within sixty days of the Oct. 14, 2008 filing.

Other Regulatory Matters NSP-Wisconsin

Bay Front Biomass Gasification Announcement On Sept. 30, 2008, NSP-Wisconsin publicly announced a plan to submit an application to the PSCW for a certificate of authority to install biomass gasification technology at the Bay Front Power Plant in Ashland, Wisc. Currently, two of the three boilers at Bay Front use biomass as their primary fuel to generate electricity. The proposed project will convert the existing coal-fired unit to biomass gasification technology allowing the plant to use 100 percent biomass in all three boilers. This is the first time biomass gasification technology will be used to convert a coal-fired boiler at an existing base-load power plant. When complete, the Bay Front Power Plant will be the largest biomass-fueled power plant in the Midwest and one of the largest in the nation. Contingent upon final approval by the Xcel Energy Board of Directors, the company expects to file an application with the PSCW later this year. Following all state regulatory approvals, engineering, design and construction work are expected to begin in 2010 and the unit could be operational in late 2012. The preliminary estimate of the project cost is $55 to $70 million. If approved, the project will improve the environmental performance of the plant and contribute towards state renewable energy standards in the region.

Other Regulatory Matters PSCo

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

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

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

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

PSCo Regulatory Policy Initiative In February 2008, the CPUC held a deliberation meeting in which they identified and discussed a set of policy initiatives that they intended to pursue over the course of 2008. At its March 2008 open meetings, the CPUC both discussed and voted to open an investigatory docket that will review the current regulatory structure to determine if current utility incentives are aligned with state public policy objectives and to determine if the existing structure is internally consistent in achieving these objectives. The CPUC expects to explore alternative forms of ratemaking for utilities and to better understand the state of the art on different mechanisms across the nation. Other policy initiatives included a transmission investigatory docket, which was opened on June 13, 2008, whose focus is to gather information on transmission planning in Colorado and transmission planning coordination with other states and utilities. On Sept. 17, 2008, the CPUC opened a customer incentives docket whose scope covers how regulatory structure and incentives influence customer decisions.

Several parties, including PSCo filed comments in the utility incentive docket in September 2008. The comments covered a wide array of issues including the best way to deliver DSM services to customers, the implications to utilities of owning generation or acquiring it through power purchase agreements and whether there should be revisions to the current regulatory structure including continued use of rate riders, and other measures to reduce regulatory lag. The CPUC held a hearing on Oct. 16, 2008 to gain further information from parties.

PSCo Resource Plan PSCo estimates it will purchase approximately 40 to 50 percent of its total electric system energy needs for 2008 and generate the remainder with PSCo-owned resources. Additional capacity has been secured under contract making additional energy available for purchase, if required. PSCo currently has under contract or through owned generation, the resources necessary to meet its anticipated 2008 load obligation. In November 2007, PSCo filed the Colorado Resource Plan (CRP), which details the type and amount of resources that will be added to the system for an eight year Resource Acquisition Period (RAP) through 2015. Hearings concluded on July 11, 2008 and a written order was issued on Sept. 19, 2008. The approved plan:

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- Increases renewable portfolio to 850 MW by 2015. PSCo would then have a total of approximately 1,900 MW of wind power resources.

- Provides for approximately 200 MW from a central solar thermal facility with storage, with possible option of acquiring up to 600 MW of solar thermal resources with storage as technology develops.

- Increases customer efficiency and conservation programs with plans to meet the CPUC goals of annual energy sales reductions to approximately 3,669 gigawatt hours, that would yield a demand savings in the range of 886 MW to 994 MW by 2020.

- Retires two older coal-burning plants (two units at Arapahoe and two units at Cameo) replacing the capacity with company owned resources providing the costs are reasonable.

Other Regulatory Matters SPS

Performance-Based Regulation and Quality of Service Requirements In Texas, SPS is subject to a quality of service plan requiring SPS to comply with electric service reliability performance targets. In January 2008, the PUCT staff served SPS with notice that it had initiated an investigation to determine whether SPS is in compliance with the Texas Statutes and PUCT rules on reliability and continuity of service. SPS agreed to settle this compliance issue with a $48,000 penalty.

Texas Energy Efficiency Cost Recovery Factor (EECRF) Rider On June 2, 2008, SPS filed with the PUCT for approval of an EECRF Rider. PUCT regulations established the mechanism under which electric utilities may recover costs associated with providing energy efficiency programs. That mechanism, an EECRF Rider, must be included in a utility s tariff and may be established in a utility s base rate case or through a separate request seeking to establish an EECRF. In accordance with this rule, SPS has removed its energy efficiency costs from its recent base rate proceeding, and has requested implementation of its EECRF Rider to recover the remaining unamortized balance of historic costs and its projected 2008 and 2009 energy efficiency costs. SPS requests that the rider be implemented on Jan. 1, 2009. On Sept. 15, 2008, the PUCT concluded that the rule under which the application was filed does not apply to SPS and the energy efficiency costs could be recovered in the pending Texas retail base rate case.

Texas Interruptible Credit Option and Saver s Switch On May 13, 2008, SPS filed an application with the PUCT and each of the 80 municipalities in SPS Texas service territory with original rate jurisdiction to revise its Interruptible Credit Option (ICO) tariff and to institute a new Saver s Switch tariff for residential and small commercial customers. The purpose of these programs is to mitigate peak demand on SPS system starting with the 2009 summer peak. The issue of cost recovery will be handled in the Texas rate case. SPS filed its unopposed settlement and proposed final order in October 2008. The tariffs will be effective Jan. 1, 2009.

Texas Renewable Energy Zone**s** In 2007, the PUCT designated competitive renewable energy zones (CREZs), which are regions of the state that are sufficient to develop renewable energy generation sources, such as wind. Several CREZ areas within the SPS service region were designated for potential development. 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. On Aug. 15, 2008, the PUCT issued a final order identifying a transmission plan to deliver approximately 18,000 MW of wind energy to load centers in ERCOT. The plan includes lines in the Texas Panhandle. Cost of this transmission plan is almost $5 billion, not including collector lines, and it will be paid for by ERCOT customers, not by SPS. A proceeding is now underway at the PUCT to select transmission providers to construct CREZ lines and associated facilities. This step is expected to be completed in the first quarter 2009, after which transmission providers will begin preparing certification applications.

New Mexico Energy Efficiency Disincentive Rulemaking During the last legislative session, increased energy efficiency goals and more affirmative disincentive language were adopted. The NMPRC is currently holding a rulemaking to update the energy efficiency rule, consistent with the legislative changes.

Environmental, Legal and Other Matters

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

Critical Accounting Policies

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which all may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures

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used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed. Item 7, Management s Discussion and Analysis, in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, includes a discussion of accounting policies that are most significant to the portrayal of Xcel Energy s financial condition and results, and that require management s most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Pending Accounting Changes

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

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy and its subsidiaries are exposed to a variety of market risks as disclosed in Management s Discussion and Analysis in its Annual Report on Form 10-K for the year ended Dec. 31, 2007. Market risk is the potential loss or gain that may occur as a result of changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk.

Xcel Energy s market risks are presented in Item 7A of Xcel Energy s 2007 Annual Report on Form 10-K, which is incorporated herein by reference. As a result of developments in the financial markets since the filing of the 2007 Annual Report on Form 10-K, we are providing below an update of the company s exposure to market risk. Commodity trading and Value-at-risk (VaR) information is provided below for informational purposes.

Xcel Energy is exposed to the impact of changes in price for energy and energy related products, which is partially mitigated by the company s use of commodity derivatives. Though no material non-performance risk currently exists with the counterparties to Xcel Energy s commodity derivative contracts, the continued turmoil in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Continued distress in the financial markets may also impact the fair value of the debt and equity securities in the nuclear decommissioning trust fund and master pension trust, as well as Xcel Energy s ability to earn a return on short-term investments of excess cash. Also, as discussed further in the Liquidity and Capital Markets section, the current state of the financial markets may negatively impact Xcel Energy s ability to obtain debt and equity financing under favorable terms.

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

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

The fair value of the commodity trading contracts at Sept. 30, 2008 were as follows:

	Nine months ended Sept. 30,	
(Millions of Dollars)	**2008**	**2007**
Fair value of commodity trading contract assets (liabilities) outstanding at Jan. 1	$ 6.3	$ (1.2)
Contracts realized or settled during the period	(3.9)	(8.4)
Fair value of commodity trading contract additions and changes during the period	2.3	15.9
Fair value of commodity trading contract assets outstanding at Sept. 30	$ 4.7	$ 6.3

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As of Sept. 30, 2008, fair values by source for the commodity trading net asset (liability) balances were as follows:

(Thousands of Dollars)	Source of Fair Value	Futures/Forwards Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 585	$ 750	$	$	$ 1,335
	2	1,821				1,821
PSCo	1	(399)				(399)
	2	1,833	140			1,973
Total Futures/Forwards Fair Value		$ 3,840	$ 890	$	$	$ 4,730

(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	$ (88)	$	$	$	$ (88)
Total Options Fair Value		$ (88)	$	$	$	$ (88)

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

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

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

At Sept. 30, 2008, a 10 percent increase in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.1 million. At Sept. 30, 2008, a 10 percent decrease in market prices over the next 12 months for commodity trading contracts would decrease pretax income from continuing operations by approximately $0.2 million.

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

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

	Period Ended Sept. 30, 2008	Change from Period Ended June 30, 2008	VaR Limit	Average	High	Low
Commodity Trading (a)	$ 0.21	$ (0.15)	$ 5.00	$ 0.33	$ 1.14	$ 0.07

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

Interest Rate Risk

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

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At Sept. 30, 2008, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $5.6 million annually, or approximately $1.4 million per quarter. See Note 10 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries interest rate derivatives.

NSP-Minnesota maintains trust funds, as required by the NRC, to fund costs of nuclear decommissioning. These trust funds are subject to interest rate risk and equity price risk. At Sept. 30, 2008, these funds were invested primarily in domestic and international equity securities and fixed-rate fixed-income securities. These funds may be used only for activities related to nuclear decommissioning. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk

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

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

At Sept. 30, 2008, a 10 percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $9.1 million, while a decrease of 10 percent would have resulted in a decrease of $6.9 million.

Fair Value Measurements

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

Commodity Derivatives Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty s ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was immaterial to the fair value of commodity derivative assets at Sept. 30, 2008. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric utility revenues. Credit risk adjustments for short-term wholesale instruments are deferred as regulatory assets and liabilities, reflecting the impact of regulatory recovery.

Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2008.

Commodity derivatives assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent approximately 7 percent and 63 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2008.

Determining the fair value of a FTR requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management s forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities include $86.9 million and $61.8 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2008.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. Level 3 commodity derivatives assets and liabilities include $6.6 million and $3.9 million of estimated fair values, respectively, for commodity forwards and options held at Sept. 30, 2008.

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Nuclear Decommissioning Fund Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities, however, less observable and subjective risk-based adjustments to estimated yield and forecasted prepayments are often significant to these valuations. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $114.0 million in the nuclear decommissioning fund at Sept. 30, 2008 (approximately 9 percent of total assets measured at fair value), are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	Nine months ended Sept. 30, 2008		2007	
Cash provided by (used in) operating activities				
Continuing operations	$	1,222	$	1,339
Discontinued operations		(11)		57
Total	$	1,211	$	1,396

Cash provided by operating activities for continuing operations decreased by $185 million for the first nine months of 2008, compared with the first nine months of 2007. This decrease was due to the timing of working capital activity and a reclassification of $28.8 million from cash equivalents to prepayments and other as a result of amounts not expected to mature within 90 days from the Reserve Primary Fund, see further discussion below.

(Millions of Dollars)	Nine months ended Sept. 30, 2008		2007	
Cash used in investing activities				
Continuing operations	$	(1,585)	$	(1,445)
Total	$	(1,585)	$	(1,445)

Cash used in investing activities for continuing operations increased by $140 million for the first nine months of 2008, compared with the first nine months of 2007. The increase was due to increased capital expenditures and an investment in the WYCO pipeline and storage project, and a reclassification of $28.8 million from cash equivalents to prepayments and other as a result of amounts not expected to mature within 90 days from the Reserve Primary Fund, see further discussion below.

(Millions of Dollars)	Nine months ended Sept. 30, 2008		2007	
Cash provided by financing activities				
Continuing operations	$	706	$	389

Total	$	706	$	389

Cash provided by financing activities for continuing operations increased by $317 million for the first nine months of 2008, compared with the first nine months of 2007. The increase is due to the issuance of long-term debt and 17,250,000 shares of common stock in the third quarter of 2008. This was partially offset by repayments of short-term borrowings.

Liquidity

General As a result of recent volatile conditions in global capital markets, including the bankruptcy filing of Lehman Brothers Holdings, Inc. (Lehman), general liquidity in short-term credit markets has been constrained despite several pro-active intervention measures undertaken by the Federal Reserve, the Department of the Treasury, the United States Congress and the President of the United States. Xcel Energy has maintained access to short-term liquidity through the A2/P2 commercial paper market and utilization of direct borrowing on certain committed credit agreements. In addition, Xcel Energy s overall liquidity through the third quarter was strengthened by the issuance of long-term debt, equity and hybrid securities completed during the third quarter and earlier in 2008. The proceeds from these financings were used to refinance maturing debt obligations, repay short-term debt and general corporate purposes.

Short-term investments Xcel Energy, NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating accounts with Wells Fargo Bank. At Sept. 30, 2008, approximately $315.0 million of cash was held in these liquid operating accounts.

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The Reserve Primary Fund On Sept. 17, 2008, NSP-Wisconsin redeemed a $40 million principal investment held in The Reserve Primary Fund (the Fund) at $0.97 per share, resulting in a loss of $1.2 million. This redemption occurred following an announcement by the Fund on Sept. 16, 2008 that the net asset value of the Fund had declined to $0.97 per share following a $785 million write-off of securities issued by Lehman.

On Sept. 29, 2008, the Fund issued an announcement that its Board of Trustees had voted to liquidate its assets and to make a cash distribution to investors in the Fund, including investors who had submitted redemption orders that had not been funded. A total distribution of $20 billion, which represents 32 percent of the Fund s total assets as of Sept. 12, 2008, will be made to all investors pro rata in proportion to the number of shares each investor held. NSP-Wisconsin s pro rata share of this distribution is projected to be approximately $10 million.

The Fund s Board of Trustees is working with the SEC to develop a plan to distribute the remaining assets of the Fund in a fair and equitable manner to all shareholders. The Fund cannot currently estimate when additional distributions to investors will be made.

Long-term investments The recent volatility in global capital markets has lead to a reduction in the current value of long-term investments held in Xcel Energy s nuclear decommissioning trust fund and pension fund.

The nuclear decommissioning trust fund invests in a diversified portfolio of taxable and municipal fixed income securities and equity securities. At Sept. 30, 2008, the total value of the nuclear decommissioning trust fund was approximately $1.187 billion as compared to $1.318 billion at December 31, 2007. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset or liability on Xcel Energy s consolidated balance sheet.

Xcel Energy s pension assets are invested in a diversified portfolio of domestic and international equity securities, fixed income securities, real estate and alternative investments, including private equity funds and a commodities index. At Sept. 30, 2008, the total value of the pension assets was $2.569 billion as compared to $3.186 billion at Dec. 31, 2007. The recent decline in asset value for the plan could require additional future funding requirements greater than the $35 million annual contribution that Xcel Energy funded earlier this year to one of its plans.

Commodity Trading On Sept. 14, 2008, Lehman filed bankruptcy. Xcel Energy has no direct credit exposure in its short-term wholesale and commodity trading activity to Lehman, or its subsidiaries. Xcel Energy has been informed by PJM, an RTO operating primarily in the mid-Atlantic, that Lehman has defaulted on a guaranty issued to a Lehman subsidiary operating within the PJM market, and this technical default has not been cured. According to PJM rules, the Lehman subsidiary will be required to liquidate its positions within the PJM market, if this technical default is not cured. Any losses encountered during a liquidation of PJM positions will be socialized to all PJM market participants, which includes certain Xcel Energy utility subsidiaries. Xcel Energy has no additional information to quantify the risk to PJM given this default. However, given the level of activity the Xcel Energy utility subsidiaries conduct in the PJM market, Xcel Energy believes the impact will be immaterial.

Commercial Paper Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $800 million for Xcel Energy,
- $500 million for NSP-Minnesota,
- $700 million for PSCo and
- $250 million for SPS.

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

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

The borrowings or loans outstanding at Sept. 30, 2008, and the short-term borrowing limits from the money pool are as follows:

(Millions of Dollars)	Borrowings (Loans)	Total Borrowing Limits
NSP-Minnesota	$	$ 250
PSCo	(96)	250
SPS	96	100

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Xcel Energy and Utility Subsidiary Credit Facilities As of Oct. 21, 2008, Xcel Energy had the following credit facilities available to meet its liquidity needs:

(Millions of Dollars) **Company**	**Facility(1)**	**Drawn(2)**	**Available**	**Cash(3)**	**Liquidity**	**Maturity**
NSP-Minnesota	$ 482.2	$ 6.0	$ 476.2	$ 44.1	$ 520.3	December 2011
PSCo	675.1	7.4	667.7	87.7	755.4	December 2011
SPS	244.6	140.1	104.5	74.9	179.4	December 2011
Xcel Energy Holding Company	771.6	428.7	342.9	21.2	364.1	December 2011
Other				83.1	83.1	
Total	$ 2,173.5	$ 582.2	$ 1,591.3	$ 311.0	$ 1,902.3	

On Oct. 10, 2008, Xcel Energy borrowed $250 million under the Xcel Energy $800 million credit agreement and SPS borrowed $125 million under the SPS $250 million credit agreement. Xcel Energy and SPS took these steps to provide additional certainty of short-term funding until liquidity improves in the A2/P2 commercial paper market. Both of these borrowings are Alternative Borrowing Rate (ABR) loans bearing interest at 4.5 percent and are due and payable on Dec. 11, 2011. All or a portion of these loans may be prepaid in advance of the due date. These are the only direct borrowings outstanding on Xcel Energy s and its subsidiaries credit agreements. Subject to the terms and conditions of each of the credit agreements, funds are available for borrowing under each facility through the day prior to the expiration date.

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(1) Reflects a reduction in the commitments resulting from the Lehman Brothers bankruptcy, which reduce the credit facilities by $80 million, collectively.

(2) Includes direct borrowings, outstanding commercial paper and letters of credit.

(3) Reflects the payment of common dividends on Oct. 21, 2008.

Listed below is a summary of the banks that make up the credit facilities of Xcel Energy and its subsidiaries as of October 21, 2008.

(Millions of Dollars)

Bank	Xcel Energy Holding Co	PSCo	SPS	NSP-Minnesota	Total
Barclays Bank	$ 54.22	$ 47.44	$ 16.94	$ 33.90	$ 152.50
JP Morgan	54.22	47.44	16.94	33.90	152.50
Bank of America	42.67	37.33	13.33	26.67	120.00
Bank of NY	42.67	37.33	13.33	26.67	120.00
Bank of Tokyo/Mitsubishi	42.67	37.33	13.33	26.67	120.00
BMO Capital Markets	42.67	37.33	13.33	26.67	120.00
BNP Paribas	42.67	37.33	13.33	26.67	120.00
Citibank	42.67	37.33	13.33	26.67	120.00
Key Bank	42.67	37.33	13.33	26.67	120.00
Morgan Stanley Bank	42.67	37.33	13.33	26.67	120.00
Royal Bank of Scotland	42.67	37.33	13.33	26.67	120.00
Scotia Capital	42.67	37.33	13.33	26.67	120.00
UBS	42.67	37.33	13.33	26.67	120.00
Wells Fargo	42.67	37.33	13.33	26.67	120.00
Credit Suisse	28.44	24.89	8.89	17.78	80.00
Goldman Sachs	28.44	24.89	8.89	17.78	80.00
Merrill Lynch	28.44	24.89	8.89	17.78	80.00
Mizuho	28.44	24.89	8.89	17.78	80.00
US Bank	28.44	24.89	8.89	17.78	80.00
Amarillo National Bank	8.89	7.78	2.78	5.55	25.00
Sumitomo			3.50		3.50
Lehman Brothers Bank					
Total	$ 771.57	$ 675.07	$ 244.57	$ 482.29	$ 2,173.50

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Credit Agency Ratings Short-term borrowing, as a source of funding, is affected by regulatory actions and access to reasonably priced capital markets. This access is dependent in part on credit agency reviews and ratings. The following ratings reflect the views of Moody s Investor Services, Inc., Standard & Poor s Ratings Services, and Fitch Ratings. 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. 20, 2008, the following table represents the credit ratings assigned to various Xcel Energy companies:

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

Registration Statements NSP-Wisconsin filed a registration statement in June 2008 and SPS filed a registration statement in August 2008.

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

Future Financing Plans

Xcel Energy generally expects to fund its operations and capital investments through internally generated funds and periodically issue short-term debt, long-term debt, common stock, preferred stock and hybrid securities. Xcel Energy plans to issue commercial paper or draw down on its credit facilities to meet short-term working capital requirements.

Xcel Energy expects the note holders to convert the $57.5 million principal balance of its Senior Convertible Notes due Nov. 21, 2008, to common equity by the maturity date of the notes.

SPS plans to issue up to $250 million of long-term senior debt securities in the fourth quarter of 2008 or early 2009 to repay short term debt, pre-fund the maturity of $100 million senior notes due March 1, 2009, fund utility capital expenditures and to provide funds for general corporate purposes.

Earnings Guidance

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

	2008 Diluted Earnings Per Share Range
Utility operations	$1.61 - $1.66
Holding company financing costs and other	(0.16)
Xcel Energy earnings per share	**$1.45 - $1.50**

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Key Assumptions for 2008:

- Normal weather patterns are experienced for the remainder of the year.
- Various riders, associated with MERP, Minnesota and Colorado transmission and Minnesota renewable energy, are expected to increase revenue by approximately $55 million to $65 million over 2007 levels.
- Reasonable regulatory outcomes in the North Dakota electric rate case, the SPS FERC wholesale electric rate cases and interim rate recovery of capacity costs in the Texas electric rate case.
- No material incremental accruals related to the SPS regulatory proceedings.
- Weather-adjusted retail electric utility sales grow by approximately 1.7 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 $30 million.
- Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $30 million to $35 million over 2007 levels.
- Capacity costs at PSCo are recovered under the purchased capacity cost adjustment.
- Utility operating and maintenance expenses increase between 0.0 percent and 2.0 percent.
- Depreciation and amortization and conservation and demand-side management program expense is projected to increase approximately $45 million to $55 million over 2007 levels.
- Interest expense increases approximately $20 million to $25 million over 2007 levels.
- Allowance for funds used during construction-equity increases approximately $30 million to $35 million over 2007 levels.
- An effective tax rate for continuing operations of approximately 32 percent to 35 percent.
- Average common stock and equivalents for diluted earnings per share calculations of approximately 440 million shares.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 2, Management s Discussion and Analysis Derivatives, Risk Management and 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 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in reports under the Exchange Act 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 Control Over Financial Reporting

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

Part II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

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

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Item 1A. RISK FACTORS

Xcel Energy s risk factors are documented in Item 1A of Part I of its 2007 Annual Report on Form 10-K, which is incorporated herein by reference. As a result of developments in the financial markets since the filing of the 2007 Annual Report on Form 10-K, we are providing updates below of the risk factors as follows:

We are subject to credit risks.

Credit risk includes the risk that our retail customers will not pay their bills, which may lead to a reduction in liquidity and an eventual increase in bad debt. Retail credit risk is comprised of numerous factors including the overall level of economic activity in our various service territories and price of products and services provided.

Credit risk also includes the risk that short-term wholesale and commodity trading counterparties that owe us money or product will breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

Xcel Energy may at times have direct credit exposure in its short-term wholesale and commodity trading activity to various financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. Xcel Energy may also have some indirect credit exposure due to participation in organized markets such as PJM and MISO in which any credit losses are socialized to all market participants.

Xcel Energy does have additional indirect credit exposures to various financial institutions in the form of letters of credit provided as security by power suppliers under various long-term physical purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below the designated investment grade rating stipulated in the underlying long term purchased power contracts, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party would be in technical default under the contract, which would enable Xcel Energy to exercise its contractual rights.

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, which may adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital, which are discussed in greater detail in the Capital Markets risk section in the 2007 Annual Report on Form 10-K.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers ability to pay timely, increase customer bankruptcies, and may lead to increased bad debt. It is expected that commercial and industrial customers will be impacted first with residential customers following, if such circumstances occur. See credit risk section for more related information.

Further worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure, such as steel, copper, aluminum, etc., which may impact our ability to acquire sufficient supplies. Additionally, the cost of those commodities may be higher than expected.

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

None.

Item 5. OTHER INFORMATION

On Aug. 12, 2008, our Board of Directors approved amendments to our Bylaws to adopt specific advance-notice requirements for shareholder-sponsored director nominations and to expand the disclosure that shareholders must make when submitting a director nomination or other proposal for business to be brought before a meeting of shareholders but not included in our proxy statement.

Article 2, Section 18 is a new addition to the Bylaws and governs the notice requirements for shareholder submissions of director nominations. If the date of the annual meeting of shareholders is not more than 30 days before or after the first anniversary of the date of the preceding year s annual meeting of shareholders, then Article 2, Section 18 provides for a standard advance-notice period for shareholder nominations of not less than 90 days prior to the first anniversary of the preceding year s annual meeting of shareholders.

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The 2008 annual meeting of shareholders was held on May 21, 2008. Therefore, as long as the 2009 annual meeting of shareholders is held no earlier than April 21, 2009 and no later than June 20, 2009, shareholder director nominations must be received by Feb. 20, 2009 instead of between Jan. 1, 2009 and Feb. 15, 2009, which was the deadline previously disclosed in the 2008 proxy statement.

In addition, Article 6, Section 11 was amended and governs the notice requirements for shareholder proposals for business other than director nominations to be brought before a meeting of shareholders. If the date of the annual meeting of shareholders is not more than 30 days before or after the first anniversary of the date of the preceding year s annual meeting of shareholders, then Article 6, Section 11 provides for a standard advance-notice period for shareholder proposals of not less than 90 days prior to the first anniversary of the preceding year s annual meeting of shareholders. As above, as long as the 2009 annual meeting of shareholders is held no earlier than April 21, 2009 and no later than June 20, 2009, shareholder proposals for business other than director nominations must be received by Feb. 20, 2009 instead of between Jan. 1, 2009 and Feb. 15, 2009, which was the deadline previously disclosed in the 2008 proxy statement.

Finally, the amendments to our Bylaws require a shareholder who submits a nomination or other proposal to disclose, among other things, any derivative interests in, and voting arrangements with respect to, our securities in addition to the shareholder s outright record and beneficial ownership.

The foregoing amendments do not change the date by which shareholder proposals must be received to be considered for inclusion in the 2009 proxy statement. That deadline remains 5:00 p.m. CST on Dec. 2, 2008, as further discussed in the 2008 proxy statement. Furthermore, the foregoing amendments do not change the date by which a shareholder s recommendation of an individual for consideration as a nominee for director must be received by our Governance, Compensation and Nominating Committee. That deadline remains Oct. 10, 2008.

Item 6. EXHIBITS

* Indicates incorporation by reference

3.01*	Restated Articles of Incorporation of Xcel Energy, as amended on May 21, 2008. (Exhibit 3.01 to Form 10-Q for the quarter ended June 30, 2008 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
4.01*	Supplemental Indenture dated as of Aug. 1, 2008 between Public Service Company of Colorado and U.S. Bank Trust National Association, as successor Trustee, creating $300,000,000 principal amount of 5.80% First Mortgage Bonds, Series No. 18 due 2018 and $300,000,000 principal amount of 6.50% First Mortgage Bonds, Series No. 19 due 2038 (Exhibit 4.01 of Form 8-K of Public Service Company of Colorado dated Aug. 6, 2008 (file no. 001-03280)).
4.02*	Supplemental Trust Indenture dated as of Sept. 1, 2008 between Northern States Power Company (Wisconsin) and U.S. Bank National Association, as successor Trustee, creating $200,000,000 principal amount of 6.375% First Mortgage Bonds, Series due Sept. 1, 2038 (Exhibit 4.01 of Form 8-K of Northern States Power Company, a Wisconsin corporation, dated Sept. 3, 2008 (file no. 001-03140)).
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.

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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. 24, 2008