XCEL ENERGY INC
Form 10-Q
October 31, 2014

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 Sept. 30, 2014
or

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

Commission File Number: 001-3034
Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if smaller reporting company)	Smaller reporting company ¨

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

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

Class	Outstanding at October 24, 2014
Common Stock, $2.50 par value	505,685,923 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, which is operated on an integrated basis and is managed by NSP-Minnesota, is referred to collectively as the NSP System. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION

Item 1 — FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)
(amounts in thousands, except per share data)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2014	2013	2014	2013
Operating revenues				
Electric	$2,616,351	$2,599,925	$7,215,699	$6,911,998
Natural gas	236,649	205,358	1,485,464	1,216,275
Other	16,807	17,055	56,344	55,827
Total operating revenues	2,869,807	2,822,338	8,757,507	8,184,100
Operating expenses				
Electric fuel and purchased power	1,079,855	1,097,944	3,188,498	3,034,031
Cost of natural gas sold and transported	99,344	74,847	934,073	702,987
Cost of sales — other	8,012	7,540	24,783	23,832
Operating and maintenance expenses	568,391	575,305	1,714,138	1,667,093
Conservation and demand side management program expenses	75,172	67,811	223,552	192,288
Depreciation and amortization	255,395	228,491	756,645	721,131
Taxes (other than income taxes)	117,958	105,287	358,938	320,765
Total operating expenses	2,204,127	2,157,225	7,200,627	6,662,127
Operating income	665,680	665,113	1,556,880	1,521,973
Other income (expense), net	1,404	(404)	4,687	3,931
Equity earnings of unconsolidated subsidiaries	7,401	7,273	22,650	22,379
Allowance for funds used during construction — equity	23,337	21,284	68,852	63,147
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,737, $6,020, $17,144 and $24,058, respectively	143,219	144,542	421,713	431,026
Allowance for funds used during construction — debt	(9,948)	(9,377)	(29,609)	(28,451)
Total interest charges and financing costs	133,271	135,165	392,104	402,575
Income before income taxes	564,551	558,101	1,260,965	1,208,855
Income taxes	195,969	193,349	435,998	410,676
Net income	$368,582	$364,752	$824,967	$798,179
Weighted average common shares outstanding:				
Basic	506,082	498,149	502,983	495,256
Diluted	506,365	498,641	503,213	495,767
Earnings per average common share:				
Basic	$0.73	$0.73	$1.64	$1.61

Diluted	0.73	0.73	1.64	1.61
Cash dividends declared per common share	$0.30	$0.28	$0.90	$0.83

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2014	2013	2014	2013
Net income	$368,582	$364,752	$824,967	$798,179
Other comprehensive income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $567, $686, $1,666 and $3,918, respectively	847	1,179	2,575	1,675
Derivative instruments:				
Net fair value (decrease) increase, net of tax of $(27), $14, $(22), and $(2), respectively	(42)	22	(34)	(9)
Reclassification of losses to net income, net of tax of $393, $266, $1,115 and $2,145, respectively	558	539	1,693	928
	516	561	1,659	919
Marketable securities:				
Net fair value increase, net of tax of $1, $73, $26 and $56, respectively	2	115	40	79
Other comprehensive income	1,365	1,855	4,274	2,673
Comprehensive income	$369,947	$366,607	$829,241	$800,852

See Notes to Consolidated Financial Statements

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

	Nine Months Ended Sept. 30	
	2014	2013
Operating activities		
Net income	$824,967	$798,179
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	769,706	740,623
Conservation and demand side management program amortization	4,582	5,024
Nuclear fuel amortization	92,278	76,447
Deferred income taxes	433,224	409,662
Amortization of investment tax credits	(4,329)	(4,973)
Allowance for equity funds used during construction	(68,852)	(63,147)
Equity earnings of unconsolidated subsidiaries	(22,650)	(22,379)
Dividends from unconsolidated subsidiaries	27,130	27,503
Share-based compensation expense	16,536	28,362
Net realized and unrealized hedging and derivative transactions	(1,354)	(12,011)
Changes in operating assets and liabilities:		
Accounts receivable	(16,080)	(108,488)
Accrued unbilled revenues	112,406	87,652
Inventories	(57,677)	(69,918)
Other current assets	(25,901)	6,060
Accounts payable	(155,788)	(3,297)
Net regulatory assets and liabilities	162,134	100,648
Other current liabilities	14,683	129,984
Pension and other employee benefit obligations	(111,463)	(159,592)
Change in other noncurrent assets	44,009	26,537
Change in other noncurrent liabilities	(33,220)	10,032
Net cash provided by operating activities	2,004,341	2,002,908
Investing activities		
Utility capital/construction expenditures	(2,301,339)	(2,454,198)
Proceeds from insurance recoveries	6,000	90,000
Allowance for equity funds used during construction	68,852	63,147
Purchases of investments in external decommissioning fund	(499,493)	(1,177,398)
Proceeds from the sale of investments in external decommissioning fund	494,554	1,172,597
Investment in WYCO Development LLC	(2,220)	(3,418)
Other, net	(1,110)	(1,524)
Net cash used in investing activities	(2,234,756)	(2,310,794)
Financing activities		
Repayments of short-term borrowings, net	(62,000)	(300,000)
Proceeds from issuance of long-term debt	837,794	1,434,989
Repayments of long-term debt, including reacquisition premiums	(275,708)	(654,864)
Proceeds from issuance of common stock	178,639	229,420
Dividends paid	(417,586)	(382,148)
Net cash provided by financing activities	261,139	327,397

Net change in cash and cash equivalents	30,724	19,511
Cash and cash equivalents at beginning of period	107,144	82,323
Cash and cash equivalents at end of period	$137,868	$101,834
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$(407,186)	$(411,130)
Cash (paid) received for income taxes, net	(4,950)	16,851
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$407,706	$299,209
Issuance of common stock for reinvested dividends and 401(k) plans	42,772	54,963

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	Sept. 30, 2014	Dec. 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$137,868	$107,144
Accounts receivable, net	760,213	744,160
Accrued unbilled revenues	574,824	687,230
Inventories	634,262	576,538
Regulatory assets	415,197	417,801
Derivative instruments	120,654	91,707
Deferred income taxes	283,047	341,202
Prepayments and other	270,529	252,258
Total current assets	3,196,594	3,218,040
Property, plant and equipment, net	27,630,363	26,122,159
Other assets		
Nuclear decommissioning fund and other investments	1,816,962	1,755,990
Regulatory assets	2,488,580	2,509,218
Derivative instruments	53,577	84,842
Other	177,365	217,241
Total other assets	4,536,484	4,567,291
Total assets	$35,363,441	$33,907,490
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$257,506	$280,763
Short-term debt	697,000	759,000
Accounts payable	1,061,385	1,261,238
Regulatory liabilities	379,824	274,769
Taxes accrued	371,959	378,766
Accrued interest	132,084	159,372
Dividends payable	151,623	139,432
Derivative instruments	22,924	23,382
Other	396,564	377,776
Total current liabilities	3,470,869	3,654,498
Deferred credits and other liabilities		
Deferred income taxes	5,750,946	5,331,046
Deferred investment tax credits	74,910	79,239
Regulatory liabilities	1,140,619	1,059,395
Asset retirement obligations	1,922,022	1,815,390
Derivative instruments	187,445	209,224
Customer advances	262,734	275,555
Pension and employee benefit obligations	653,599	769,222
Other	243,917	237,217

Total deferred credits and other liabilities	10,236,192	9,776,288
Commitments and contingencies		
Capitalization		
Long-term debt	11,501,720	10,910,754
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 505,424,067 and 497,971,508 shares outstanding at Sept. 30, 2014 and Dec. 31, 2013, respectively	1,263,560	1,244,929
Additional paid in capital	5,815,714	5,619,313
Retained earnings	3,177,387	2,807,983
Accumulated other comprehensive loss	(102,001)	(106,275)
Total common stockholders' equity	10,154,660	9,565,950
Total liabilities and equity	$35,363,441	$33,907,490

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value				
Three Months Ended Sept. 30, 2014 and 2013						
Balance at June 30, 2013	497,296	$1,243,239	$5,595,906	$2,572,935	$ (111,835)	$9,300,245
Net income				364,752		364,752
Other comprehensive gain					1,855	1,855
Dividends declared on common stock				(140,201)		(140,201)
Issuances of common stock	330	825	8,966			9,791
Share-based compensation			10,844			10,844
Balance at Sept. 30, 2013	497,626	$1,244,064	$5,615,716	$2,797,486	$ (109,980)	$9,547,286
Balance at June 30, 2014	505,106	$1,262,764	$5,799,968	$2,961,406	$ (103,366)	$9,920,772
Net income				368,582		368,582
Other comprehensive gain					1,365	1,365
Dividends declared on common stock				(152,601)		(152,601)
Issuances of common stock	318	796	9,135			9,931
Share-based compensation			6,611			6,611
Balance at Sept. 30, 2014	505,424	$1,263,560	$5,815,714	$3,177,387	$ (102,001)	$10,154,660

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED) (Continued)
(amounts in thousands)

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
	Shares	Par Value				
Nine Months Ended Sept. 30, 2014 and 2013						
Balance at Dec. 31, 2012	487,960	$1,219,899	$5,353,015	$2,413,816	$ (112,653)	$8,874,077
Net income				798,179		798,179
Other comprehensive gain					2,673	2,673
Dividends declared on common stock				(414,509)		(414,509)
Issuances of common stock	9,666	24,165	228,751			252,916
Share-based compensation			33,950			33,950
Balance at Sept. 30, 2013	497,626	$1,244,064	$5,615,716	$2,797,486	$ (109,980)	$9,547,286
Balance at Dec. 31, 2013	497,972	$1,244,929	$5,619,313	$2,807,983	$ (106,275)	$9,565,950
Net income				824,967		824,967
Other comprehensive gain					4,274	4,274
Dividends declared on common stock				(455,563)		(455,563)
Issuances of common stock	7,452	18,631	175,960			194,591
Share-based compensation			20,441			20,441
Balance at Sept. 30, 2014	505,424	$1,263,560	$5,815,714	$3,177,387	$ (102,001)	$10,154,660

See Notes to Consolidated Financial Statements

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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, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of Sept. 30, 2014 and Dec. 31, 2013; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and nine months ended Sept. 30, 2014 and 2013; and its cash flows for the nine months ended Sept. 30, 2014 and 2013. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after Sept. 30, 2014 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2013 balance sheet information has been derived from the audited 2013 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2013. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2013, filed with the SEC on Feb. 21, 2014. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2013, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

Revenue Recognition — In May 2014, the Financial Accounting Standards Board issued Revenue from Contracts with Customers, Topic 606 (Accounting Standards Update (ASU) No. 2014-09), which provides a framework for the recognition of revenue, with the objective that recognized revenues properly reflect amounts an entity is entitled to receive in exchange for goods and services. This guidance, which includes additional disclosure requirements regarding revenue, cash flows and obligations related to contracts with customers, will be effective for interim and annual reporting periods beginning after Dec. 15, 2016. Xcel Energy is currently evaluating the impact of adopting ASU 2014-09 on its consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2014	Dec. 31, 2013
Accounts receivable, net		
Accounts receivable	$814,967	$797,267
Less allowance for bad debts	(54,754)	(53,107)
	$760,213	$744,160

(Thousands of Dollars)	Sept. 30, 2014	Dec. 31, 2013
Inventories		
Materials and supplies	$240,384	$225,308
Fuel	193,951	189,485

Natural gas	199,927	161,745
	$634,262	$576,538

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(Thousands of Dollars)	Sept. 30, 2014	Dec. 31, 2013
Property, plant and equipment, net		
Electric plant	$32,122,904	$30,341,310
Natural gas plant	4,294,667	4,086,651
Common and other property	1,483,063	1,485,547
Plant to be retired [(a)]	77,922	101,279
Construction work in progress	2,364,851	2,371,566
Total property, plant and equipment	40,343,407	38,386,353
Less accumulated depreciation	(13,028,218)	(12,608,305)
Nuclear fuel	2,250,140	2,186,799
Less accumulated amortization	(1,934,966)	(1,842,688)
	$27,630,363	$26,122,159

(a) As a result of the 2010 Colorado Public Utilities Commission (CPUC) approval of PSCo's Clean Air Clean Jobs Act (CACJA) compliance plan and the December 2013 approval of PSCo's preferred plans for applicable generating resources, PSCo has received approval for early retirement of Cherokee Unit 3 and Valmont Unit 5 between 2015 and 2017. Amounts are presented net of accumulated depreciation.

4. Income Taxes

Except to the extent noted below, the circumstances set forth in Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Tax Loss Carryback Claims — In 2012 and 2013, Xcel Energy identified certain expenses related to 2009, 2010, 2011 and 2013 that qualify for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a tax benefit of approximately $15 million in 2012 and $12 million in 2013.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expired in September 2012. The statute of limitations applicable to Xcel Energy's 2009 federal income tax return expires in June 2015. In the third quarter of 2012, the Internal Revenue Service (IRS) commenced an examination of tax years 2010 and 2011, including the 2009 carryback claim. As of Sept. 30, 2014, the IRS had proposed an adjustment to the federal tax loss carryback claims that would result in $10 million of income tax expense for the 2009 through 2011 claims and the anticipated claim for 2013. Xcel Energy is continuing to work through the audit process, but the outcome and timing of a resolution is uncertain.

State Audits — Xcel Energy files consolidated 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. As of Sept. 30, 2014, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2009
Minnesota	2009
Texas	2009
Wisconsin	2010

In the first quarter of 2014, the state of Wisconsin completed an examination of tax years 2009 through 2011. No material adjustments were proposed for those tax years. As of Sept. 30, 2014, there were no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions 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 ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

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A reconciliation of the amount of unrecognized tax benefit is as follows:

(Millions of Dollars)	Sept. 30, 2014	Dec. 31, 2013
Unrecognized tax benefit — Permanent tax positions	$7.5	$12.9
Unrecognized tax benefit — Temporary tax positions	32.9	28.3
Total unrecognized tax benefit	$40.4	$41.2

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	Sept. 30, 2014	Dec. 31, 2013
NOL and tax credit carryforwards	$(28.1)	$(27.1)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS audit progresses and state audits resume. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefit could decrease up to approximately $8 million.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at Sept. 30, 2014 and Dec. 31, 2013 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 30, 2014 or Dec. 31, 2013.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Pending Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

NSP Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the MPUC. The rate case is based on a requested return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015.

The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million or 6.9 percent in 2014 and an additional $98 million or 3.5 percent in 2015. The request includes a proposed rate moderation plan for 2014 and 2015. After reflecting interim rate adjustments, NSP-Minnesota requested a rate increase of $127 million or 4.6 percent in 2014 and an incremental rate increase of $164 million or 5.6 percent in 2015.

NSP-Minnesota's moderation plan includes the acceleration of the eight-year amortization of the excess depreciation reserve and the use of expected funds from the U.S. Department of Energy (DOE) for settlement of certain claims. These DOE refunds would be in excess of amounts needed to fund NSP-Minnesota's decommissioning expense. The interim rate adjustments are primarily associated with ROE, Monticello life cycle management (LCM)/extended power uprate (EPU) project costs and NSP-Minnesota's request to amortize amounts associated with the canceled Prairie Island (PI) EPU project.

In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund. The MPUC determined that the costs of Sherco Unit 3 would be allowed in interim rates, and that NSP-Minnesota’s request to accelerate the depreciation reserve amortization was a permissible adjustment to its interim rate request.

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In August 2014, the evidentiary hearing was completed. As a result of discussions between NSP-Minnesota and intervening parties, the outstanding issues were further narrowed and the following were agreed upon:

- NSP-Minnesota and the Minnesota Department of Commerce (DOC) have agreed to true-up the sales forecast to 12 months of actual weather normalized sales for 2014.
- NSP-Minnesota and the DOC agreed to a property tax adjustment of $9 million, based on an assumed 2014 property tax forecast of $141 million. The parties also agreed to a limited true-up mechanism in which NSP-Minnesota would recover actual 2014 property taxes up to $145 million.
- NSP-Minnesota agreed with the Minnesota Chamber of Commerce recommendation regarding deferral of the 2014 Monticello EPU depreciation expense and amortization of the depreciation over the remaining life of the plant.

NSP-Minnesota revised its requested rate increase to $142.2 million for 2014 and to $106.0 million for 2015, for a total combined increase of $248.2 million.

The following table summarizes the DOC's and NSP-Minnesota's recommendations and includes the estimated impact of certain agreed-upon true-up adjustments:

2014 Rate Request (Millions of Dollars)	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$192.7	$192.7
Sales forecast	(43.2)	(15.8)
ROE	(36.2)	—
Monticello EPU cost recovery	(33.9)	—
Monticello EPU depreciation deferral	—	(12.2)
Property taxes	(9.0)	(9.0)
PI EPU	(5.1)	(5.1)
Health care, pension and other benefits	(11.4)	(1.9)
Other, net	(8.0)	(6.5)
Total recommendation 2014 — unadjusted	$45.9	$142.2
Estimated true-up adjustments:		
Sales forecast	$18.3	$(9.1)
Property taxes	3.9	3.9
Total recommendation 2014 — adjusted	$68.1	$137.0

2015 Rate Request (Millions of Dollars)	DOC	NSP-Minnesota
NSP-Minnesota's filed rate request	$98.5	$98.5
Monticello EPU cost recovery	29.1	—
Monticello EPU cost disallowance [(a)]	(10.2)	—
Excess depreciation reserve adjustment [(b)]	(22.7)	—
Depreciation	(17.5)	—
Monticello EPU depreciation deferral	—	1.6
Monticello EPU step increase	—	10.1
Property taxes	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)
DOE settlement proceeds	10.1	10.1
Emission chemicals	(1.6)	(1.6)
Other, net	(4.8)	1.7
Total recommendation 2015 step increase	$66.5	$106.0
Unadjusted cumulative total for 2014 and 2015 step increase	$112.4	$248.2
Estimated adjusted cumulative total for 2014 and 2015 step increase	$134.6	$243.0

(a) In July 2014, the DOC recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis. This equates to a total NSP System disallowance of approximately $94 million. This would reduce NSP-Minnesota’s revenue requirement by approximately $10.2 million in 2015.

(b) Adjustment is due to timing differences and/or methodology of accelerating amortization of the excess depreciation reserve over three years.

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NSP-Minnesota's revised rate request, moderation plan, interim rate adjustments and impacts on expenses are detailed below:

(Millions of Dollars)	2014	Percentage Increase	2015	Percentage Increase
Rebuttal pre-moderation deficiency	$250.6		$67.8	
Evidentiary hearing adjustments	(27.3)		11.0	
Revised pre-moderation deficiency	223.3		78.8	
Moderation plan:				
Excess depreciation reserve	(81.1)		52.9	
DOE settlement proceeds	—		(25.7)	
Revised rate request	142.2	5.1%	106.0	3.8%
Interim rate adjustments	(65.3)		65.3	
PI EPU	4.8		(4.8)	
Revenue impact [(a)]	81.7		166.5	
Excess depreciation reserve	81.1		(45.7)	
Sales forecast [(b)]	(9.1)		—	
DOE settlement proceeds	—		25.7	
Estimated impact of request on operating income	$153.7		$146.5	

(a) NSP-Minnesota's total revenue for 2014 is capped at the interim rate level of $127 million and pre-tax operating income is capped at $208 million. This table demonstrates the impact of reducing NSP-Minnesota's rebuttal request.

(b) NSP-Minnesota and the DOC have agreed to a sales true-up based on weather normalized sales for 2014, using standard weather coefficients. NSP-Minnesota periodically adjusts the coefficients in periods of extreme weather conditions to enhance weather impact estimates. As a result of the difference in the two methodologies, currently, approximately $9.1 million of revenue that NSP-Minnesota attributed to weather would be considered normal sales growth using the standard weather coefficients. The refund for the full year could vary from the estimate as of Sept. 30, 2014, depending on weather conditions.

NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with interim rates as of Sept. 30, 2014.

The next step in the procedural schedule is expected to be the Administrative Law Judge (ALJ) Report on Dec. 26, 2014. The MPUC is expected to deliberate on March 26, 2015. A final MPUC order is anticipated in the second quarter of 2015.

NSP-Minnesota – Nuclear Project Prudence Investigation — In 2013, NSP-Minnesota completed the Monticello LCM/EPU project. The multi-year project extended the life of the facility and increased the capacity from 600 to 671 megawatts (MW). Monticello LCM/EPU project expenditures were approximately $665 million. Total capitalized costs were approximately $748 million, which includes allowance for funds used during construction (AFUDC). Project expenditures were initially estimated in 2008 at approximately $320 million, excluding AFUDC.

In 2013, the MPUC initiated an investigation to determine whether the final costs for the Monticello LCM/EPU project were prudent.

NSP-Minnesota filed a report to support the change and prudence of the incurred costs. The filing indicated the increase in costs was primarily attributable to three factors: (1) the original estimate was based on a high level conceptual design and the project scope increased as the actual conditions of the plant were incorporated into the design; (2) implementation difficulties, including the amount of work that occurred in confined and radioactive or electrically sensitive spaces and NSP-Minnesota's and its vendors' ability to attract and retain experienced workers; and

(3) additional Nuclear Regulatory Commission (NRC) licensing related requests over the five-plus year application process.

The cost deviation is in line with similar nuclear upgrade projects undertaken by other utilities. In addition, the project remains economically beneficial to customers. NSP-Minnesota has received all necessary licenses from the NRC for the Monticello EPU, and has begun the process to comply with the license requirements for higher power levels, subject to NRC oversight and review. As part of the review process, in October 2014 NSP-Minnesota received approval for ascension to higher EPU levels which is expected to recommence during the fourth quarter.

In July 2014, the DOC filed testimony and recommended a disallowance of recovery of approximately $71.5 million of project costs on a Minnesota jurisdictional basis. This equates to a total NSP System disallowance of approximately $94 million.

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The DOC's recommendation indicated that although the combined LCM/EPU project is cost effective, NSP-Minnesota should have done a better job of estimating initial project costs of the investments required to achieve 71 MW of additional capacity (i.e., EPU costs) as opposed to investments required to extend the life of the plant. They asserted that approximately 85 percent of the total $665 million in costs were associated with project components required solely to achieve the EPU.

In August 2014, the Office of Attorney General (OAG) filed rebuttal testimony and recommended a disallowance of recovery of $321 million for the entire NSP System (based on a total capitalized cost of $748 million), and no return on $107 million. The recommended disallowance is primarily based on criticism of NSP-Minnesota's management of the project.

NSP-Minnesota believes the costs of the project were prudent and its decisions and actions do not warrant a disallowance. NSP-Minnesota's testimony is summarized as follows:

- The plant is cost-effective for customers;
- The project benefits include providing carbon-free generation through a life extension and uprate of the plant for an installed capacity of about $1,000 per kilowatt;
- The DOC was incorrect in its analysis that 85 percent of the expenditures were associated with the uprate; and
- NSP-Minnesota made prudent decisions based on the information available at the time the decisions were made.

The next steps in the procedural schedule are expected to be as follows:

- Initial Briefs — Oct. 31, 2014;
- Reply Briefs — Nov. 21, 2014;
- ALJ Report — Dec. 31, 2014; and
- MPUC Deliberation — March 6, 2015.

A final MPUC order is anticipated in the second quarter of 2015. The MPUC decision for the Monticello prudence review is expected to be reflected in the final results of NSP-Minnesota's pending Minnesota 2014 Multi-Year electric rate case.

Electric, Purchased Gas and Resource Adjustment Clauses

NSP-Minnesota – Gas Utility Infrastructure Cost (GUIC) Rider — In August 2014, NSP-Minnesota filed a GUIC rider with the MPUC for approval to recover the cost of natural gas infrastructure investments in Minnesota to improve safety and reliability. Costs include funding for pipeline assessment and system upgrades in 2015 and beyond, as well as deferred costs from NSP-Minnesota's existing sewer separation and pipeline integrity management programs. Sewer separation costs stem from the inspection of sewer lines and the redirection of gas pipes in the event their paths are in conflict. NSP-Minnesota is requesting recovery of approximately $14.9 million from Minnesota gas utility customers beginning Jan. 1, 2015, including $4.8 million of deferred sewer separation and integrity management costs which is the 2015 portion of a five year amortization. In October 2014, the DOC recommended approval of NSP-Minnesota's request for recovery of the GUIC rider, using the capital structure and cost of capital proposed in the current electric case and a five year amortization period for the deferred costs. An MPUC decision is anticipated by the end of 2014.

Pending Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. The request is based on a 2013 historic test year (HTY) adjusted for certain known and measurable changes for 2014 and 2015, a requested ROE of 10.25 percent, an average rate base of $433.2 million and an equity ratio of 53.86 percent. This request reflects NSP-Minnesota's proposal to move recovery of approximately $9.0 million for certain

Transmission Cost Recovery (TCR) rider and Infrastructure rider projects to base rates.

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The major components of the request are as follows:

(Millions of Dollars)	Request
Nuclear investments and operating costs	$13.4
Other production, transmission and distribution	5.0
Technology improvements	2.1
Pension and operating and maintenance (O&M) expenses	1.6
Wind generation facilities	1.4
Capital structure	1.1
Incremental increase to base rates	$24.6
Infrastructure rider to be included in base rates	$(8.4)
TCR rider to be included in base rates	(0.6)
Net request	$15.6

At this time, the case is in the discovery phase and further procedure scheduling may be established during the fourth quarter of 2014. In November 2014, NSP-Minnesota plans to file a request with the SDPUC for interim rates, effective Jan. 1, 2015. Final rates are anticipated to be effective in the first quarter of 2015.

NSP-Wisconsin

Pending Regulatory Proceedings — Public Service Commission of Wisconsin (PSCW)

NSP-Wisconsin – Wisconsin 2015 Electric Rate Case — In May 2014, NSP-Wisconsin filed a request with the PSCW to increase electric rates by $20.6 million, or 3.2 percent, effective Jan. 1, 2015. The request is for the limited purpose of updating 2015 electric rates to reflect anticipated increases in the production and transmission fixed charges and the fuel and purchased power components of the interchange agreement with NSP-Minnesota. No changes are being requested to the capital structure or the 10.2 percent ROE authorized by the PSCW in the 2014 rate case. As part of an agreement with stakeholders to limit the size and scope of the case, NSP-Wisconsin also agreed to an earnings cap for 2015 only, in which 100 percent of the earnings above the authorized ROE would be refunded to customers.

In October 2014, the PSCW Staff filed their direct testimony and recommended an electric rate increase of $16.1 million, or 2.5 percent. The majority of the PSCW Staff's adjustments are related to the fuel cost forecast, and are primarily the result of more recent data than was available at the time the initial filing was prepared last spring.

In October 2014, NSP-Wisconsin, the PSCW Staff and other parties reached an agreement that resolved all contested issues in the case and accepted the PSCW staff recommendation to increase NSP-Wisconsin's electric rates by approximately $16.1 million, effective January 2015.

The major cost components of the requested increase and the PSCW Staff recommendation are summarized below:

(Millions of Dollars)	NSP-Wisconsin Request	PSCW Staff Recommendation
Production and transmission fixed charges	$28.1	$26.4
Fuel and purchased power	13.9	11.1
Sub-Total	$42.0	$37.5
NSP-Minnesota transmission depreciation reserve	$(16.2)	$(16.2)
Monticello EPU deferral	(5.2)	(5.2)
Total	$20.6	$16.1

A final PSCW decision is anticipated by the end of 2014.

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Pending Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

Midcontinent Independent System Operator, Inc. (MISO) ROE Complaint — In November 2013, a group of customers filed a complaint at the FERC against MISO transmission owners, including NSP-Minnesota and NSP-Wisconsin. The complaint argues for a reduction in the ROE applicable to transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE adders (including those for regional transmission organization (RTO) membership and being an independent transmission company), effective Nov. 12, 2013.

In January 2014, Xcel Energy filed an answer to the complaint asserting that the 9.15 percent ROE would be unreasonable and that the complainants failed to demonstrate the NSP System equity capital structure was unreasonable. The MISO transmission owners separately answered the complaint, arguing the complaint should be dismissed.

In June 2014, the FERC issued an order in a different ROE proceeding adopting a new ROE methodology for electric utilities. The new ROE methodology requires electric utilities to use a two-step discounted cash flow analysis to estimate cost of equity that incorporates both short-term and long-term growth projections.

In October 2014, the FERC upheld the determination of the long term growth rate to be used together with a short term growth rate in its new ROE methodology. The FERC separately set the ROE complaint against the MISO transmission owners for settlement judge and hearing procedures, which are expected to begin later this year. The FERC directed parties to apply this methodology, but denied the complaints related to equity capital structures and ROE adders. The FERC established a Nov. 12, 2013 refund effective date. NSP-Minnesota recorded a current regulatory liability representing the current best estimate of a refund obligation associated with the new ROE as of Sept. 30, 2014. The new FERC ROE methodology is estimated to reduce transmission revenue, net of expense, between $5 million and $7 million annually for NSP-Minnesota and NSP-Wisconsin.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo – Colorado 2014 Electric Rate Case — In 2014, PSCo filed an electric rate case with the CPUC requesting an increase in annual revenue of approximately $136.0 million, or 4.83 percent. The requested 2015 rate increase reflects approximately $100.9 million for recovery of costs associated with the CACJA project. The case also requests the initiation of a CACJA rider for 2016 and 2017, which is anticipated to increase revenue recovery by approximately $34.2 million in 2016 and then decline to approximately $29.9 million in 2017. PSCo's objective is to establish a multi-year regulatory plan that provides certainty for PSCo and its customers.

The rate filing is based on a 2015 test year, a requested ROE of 10.35 percent, an electric rate base of $6.39 billion and an equity ratio of 56 percent. As part of the filing, PSCo will transfer approximately $19.9 million from the transmission rider to base rates, which will not impact customer bills. The CACJA rider is projected to recover incremental investment and expenses, based on a comprehensive plan to retire certain coal plants, add pollution control equipment to other existing coal units and add natural gas generation. The CACJA project investment is expected to be completed by 2017.

The next steps in the procedural schedule are expected to be as follows:
- Answer Testimony — Nov. 7, 2014;
- Rebuttal Testimony — Dec. 17, 2014;
- Evidentiary Hearing — Jan. 26 - Feb. 4, 2015;

- Interim rates are scheduled to be effective on Feb. 13, 2015, subject to refund; and
- A decision as well as implementation of final rates are anticipated in the second quarter of 2015.

PSCo – Manufacturer's Sales Tax Refund — PSCo defers 2012-2014 annual property taxes in excess of $76.7 million as part of its multi-year rate plan with the CPUC. To the extent that PSCo was successful in the manufacturer's sales tax refund lawsuit against the Colorado Department of Revenue, PSCo was to credit such refunds first against certain legal fees, and then against the unamortized deferred property tax balance at the end of 2014.

On June 30, 2014, the Colorado Supreme Court ruled against PSCo's claim that it was due refunds for the payment of sales taxes on purchases of certain equipment from December 1998 to December 2001. As a result of the adverse ruling, PSCo is required to reduce its 2014 property tax deferral by $10 million, as this amount will not be recovered in electric rates. This impact is reflected in PSCo's pending electric rate case before the CPUC.

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PSCo – Annual Electric Earnings Test — As part of an annual earnings test, PSCo must share with customers a portion of any annual earnings that exceed PSCo's authorized ROE threshold of 10 percent for 2012-2014. In April 2014, PSCo filed its 2013 earnings test with the CPUC proposing a refund obligation of $45.7 million to electric customers to be returned between August 2014 and July 2015. This tariff was approved by the CPUC in July 2014 and became effective Aug. 1, 2014. As of Sept. 30, 2014, PSCo has also recognized management's best estimate of an accrual for the 2014 earnings test of $52.4 million.

Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (REC) Sharing — In 2011, the CPUC approved margin sharing on stand-alone REC transactions at 10 percent to PSCo and 90 percent to customers for 2014. In 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the renewable energy standard adjustment (RESA) regulatory asset balance. PSCo's credit to the RESA regulatory asset balance was not material for the three months ended Sept. 30, 2014. For the three months ended Sept. 30, 2013, PSCo credited the RESA regulatory asset balance $6.1 million. The cumulative credit to the RESA regulatory asset balance was $104.7 million and $104.5 million at Sept. 30, 2014 and Dec. 31, 2013, respectively. The credits include the customers' share of REC trading margins and the unspent share of carbon offset funds.

In May 2014, PSCo filed with the CPUC to continue this sharing mechanism for 2015 and beyond, but remove the step increase in the sharing allocation of hybrid REC trades on margins in excess of $20 million. In July 2014, the CPUC sent the proceeding to an ALJ. On Sept. 5, 2014, PSCo, the CPUC Staff, and intervenors filed a settlement agreement to extend the current sharing mechanism without modification through 2017. On Sept. 18, 2014 the ALJ issued a final decision approving the settlement agreement.

Recently Concluded Regulatory Proceedings — FERC

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission formula rates from an HTY formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's wholesale transmission and ancillary services revenue by approximately $2.0 million annually. Various transmission customers protested the filing. In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to November 2012, subject to refund, and setting the case for settlement judge or hearing procedures.

In June 2012, several wholesale customers filed a complaint with the FERC seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012. In October 2012, the FERC consolidated this complaint with the April 2012 formula rate change filing.

In December 2013, the FERC approved a partial settlement resolving all issues related to the April 2012 transmission rate filing and June 2012 complaint other than ROE. The settlement does not materially increase 2014 transmission revenues.

In June 2014, PSCo and its transmission customers reached a settlement in principle to resolve the ROE issue in the transmission rate filing and complaint. The settlement was filed in September 2014, and in October 2014, the FERC ALJ granted PSCo a motion to place interim rates into effect using the settlement ROE beginning Oct. 1, 2014. The FERC approved the settlement in October 2014, providing a 9.72 percent ROE effective retroactive to July 1, 2012 for the PSCo transmission formula rate. PSCo recorded a current liability for the refund obligation based on the settlement terms as of Sept. 30, 2014.

PSCo – Production Formula Rate ROE Complaint — In August 2013, PSCo’s wholesale production customers filed a complaint with the FERC, and requested it reduce the stated ROEs ranging from 10.1 percent through 10.4 percent to 9.04 percent in the PSCo production sales formula rates effective Sept. 1, 2013. In June 2014, PSCo and its wholesale customers reached a settlement in principle to resolve the complaint along with the pending transmission formula rate ROE matters. The settlement was filed in September 2014, and in October 2014, the FERC ALJ granted PSCo a motion to place interim rates into effect using the settlement ROE beginning Oct. 1, 2014. The FERC approved the settlement in October 2014, providing a 9.72 percent ROE effective for the PSCo production formula rate. PSCo recorded a current liability for the refund obligation based on the settlement terms as Sept. 30, 2014.

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SPS

Pending Regulatory Proceedings — Public Utility Commission of Texas (PUCT)

SPS – Texas 2014 Electric Rate Case — In January 2014, SPS filed a retail electric rate case in Texas with each of its Texas municipalities and the PUCT for a net increase in annual revenue of approximately $52.7 million, or 5.8 percent. The net increase reflected a base rate increase, revenue credits transferred from base rates to rate riders or the fuel clause, and resetting the Transmission Cost Recovery Factor (TCRF) to zero when the final base rates become effective. In April 2014, SPS revised its request to a net increase of $48.1 million.

The rate filing was based on a HTY ending June 2013, a requested ROE of 10.40 percent, an electric rate base of approximately $1.27 billion and an equity ratio of 53.89 percent. The requested rate increase reflected an increase in depreciation expense of approximately $16 million.

In September 2014, SPS, PUCT staff, and intervenors filed a non-unanimous settlement agreement, subject to PUCT approval, which would increase SPS' rates by $37 million, or 3.5 percent, retroactive to June 1, 2014. Starting Oct. 1, 2014, SPS began collecting the rate increase through interim rates subject to refund. SPS expects to recover the rate increase for the months of June through September through a separate surcharge to be implemented by the first quarter of 2015. Based on the anticipated outcome of the rate case, SPS recognized approximately $13.3 million of revenue in the third quarter of 2014 for the surcharge.

The settlement includes an ROE of 9.7 percent solely for the purpose of calculating the AFUDC and determining baselines in future filings for the TCRF. In October 2014, the ALJs approved the stipulation and recommended that SPS file to implement the surcharge following the PUCT's final order. The PUCT is expected to rule on the settlement in 2014.

Although the parties to the settlement agreement have not prepared a calculation of the $37 million increase and do not agree about which specific costs are included, or not, in the agreed settlement revenue requirement, SPS' reconciliation of its original request to the settlement increase is as follows:

(Millions of Dollars)	Settlement Agreement	
Base rate increase request, January 2014	$81.5	
Revisions for updated information	(4.6	)
Revised request, April 2014	76.9	
Remove proposed increase in depreciation	(16.0	)
Remove adjustment allocators for certain wholesale load reduction	(12.0	)
Revised amortizations (rate case expenses, pension and other post-employment benefits expense and gain on sale to Lubbock)	(9.0	)
Non-specified settlement adjustments	(2.9	)
Settlement base rate increase	$37.0	

Electric, Purchased Gas and Resource Adjustment Clauses

TCRF Rider — In November 2013, SPS filed with the PUCT to implement the TCRF for Texas retail customers. The requested increase in revenues was $13 million. The PUCT issued an order allowing the TCRF to go into effect on an interim basis effective Jan. 1, 2014. In May 2014, the ALJ terminated the interim TCRF due to a settlement in principle being reached with intervenors and the PUCT staff in the pending Texas electric rate case. In July 2014, the PUCT approved the settlement agreement between the parties allowing SPS to recover $4 million annually through the TCRF. In September 2014, SPS filed a proposal with the PUCT to refund approximately $3.7 million during

November 2014 for interim rates collected in excess of the final rates approved. PUCT approval of the refund is pending. As of Sept. 30, 2014, SPS had recorded an accrual for the proposed refund.

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

SPS – New Mexico 2014 Electric Rate Case — In December 2012, SPS filed an electric rate case in New Mexico with the NMPRC for an increase in annual revenue of approximately $45.9 million effective in 2014. The rate filing was based on a 2014 forecast test year, a requested ROE of 10.65 percent, an electric rate base of $479.8 million and an equity ratio of 53.89 percent.

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In September 2013, SPS filed rebuttal testimony, revising its requested rate increase to $32.5 million, based on updated information and an ROE of 10.25 percent. The request reflected a base and fuel increase of $20.9 million, an increase of rider revenue of $12.1 million and a decrease to other of $0.5 million.

In March 2014, the NMPRC approved an overall increase of approximately $33.1 million. The increase reflects a base rate increase of $12.7 million and rider recovery of $18.1 million for renewable energy costs, both based on an ROE of 9.96 percent and an equity ratio of 53.89 percent. Final rates were effective April 5, 2014. In April 2014, the New Mexico Attorney General (NMAG) filed a request for rehearing. The rehearing request was denied by the NMPRC. In June 2014, the NMAG filed an appeal of the NMPRC's denial to the New Mexico Supreme Court. A decision is expected by the second quarter of 2016.

Pending Regulatory Proceedings — FERC

SPS – Wholesale Rate Complaints — In April 2012, Golden Spread Electric Cooperative, Inc. (Golden Spread), a wholesale cooperative customer, filed a rate complaint alleging that the base ROE included in the SPS production formula rate of 10.25 percent, and the SPS transmission base formula rate ROE of 10.77 percent, are unjust and unreasonable. In July 2013, Golden Spread filed a second complaint, again asking that the base ROE in the SPS production and transmission formula rates be reduced to 9.15 and 9.65 percent, respectively.

In addition to the FERC order issued for the MISO ROE complaint previously mentioned, the FERC issued orders in June 2014 consolidating the Golden Spread ROE complaints and setting them for settlement judge procedures and hearings and indicated the parties should apply the new ROE methodology to the proceedings. The FERC established effective dates for the refunds as April 20, 2012 and July 19, 2013. The complaints remain in settlement judge proceedings.

Golden Spread, along with certain New Mexico cooperatives and the West Texas Municipal Power Agency, filed a third rate complaint on Oct. 20, 2014, requesting that the base ROE in the SPS production and transmission formula rates be reduced to 8.61 percent and 9.11 percent, respectively. The complainants requested a refund effective date of Oct. 20, 2014, and that the new complaint be consolidated with the two prior complaints. FERC action is pending.

SPS – 2004 FERC Complaint Case Orders — In August 2013, the FERC issued an order on rehearing related to a 2004 complaint case brought by Golden Spread and Public Service Company of New Mexico (PNM) and an Order on Initial Decision in a subsequent 2006 production rate case filed by SPS.

The original complaint included two key components: 1) PNM's claim regarding inappropriate allocation of fuel costs and 2) a base rate complaint, including the appropriate demand-related cost allocator. The FERC previously determined that the allocation of fuel costs and the demand-related cost allocator utilized by SPS was appropriate.

In the August 2013 Orders, the FERC clarified its previous ruling on the allocation of fuel costs and reaffirmed that the refunds in question should only apply to firm requirements customers and not PNM's contractual load. The FERC also reversed its prior demand-related cost allocator decision. The FERC stated that it had erred in its initial analysis and concluded that the SPS system was a 3 coincident peak (CP) rather than a 12CP system.

In September 2013, SPS filed a request for rehearing of the FERC ruling on the CP allocation and refund decisions. SPS asserted that the FERC applied an improper burden of proof and that precedent did not support retroactive refunds. PNM also requested rehearing of the FERC decision not to reverse its prior ruling.

In October 2013, the FERC issued orders further considering the requests for rehearing. These matters are currently pending the FERC's action. If unsuccessful in its rehearing request, SPS will have the opportunity to file rate cases with the FERC and its retail jurisdictions seeking to change all customers to a 3CP allocation method.

As of Dec. 31, 2013, SPS had accrued $44.5 million related to the August 2013 Orders and an additional $4.0 million of principal and interest was accrued during the first nine months of 2014. Pending the timing and resolution of this matter, the annual impact to revenues through 2014 could be up to $6 million and decreasing to $4 million on June 1, 2015.

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6. Commitments and Contingencies

Except to the extent noted below and in Note 5, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013, 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 commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

Purchased Power Agreements (PPAs)

Under certain PPAs, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific PPAs create a variable interest in the associated independent power producing entity.

The Xcel Energy utility subsidiaries had approximately 3,698 MW and 3,338 MW of capacity under long-term PPAs as of Sept. 30, 2014 and Dec. 31, 2013, respectively, with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through 2033.

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of Sept. 30, 2014 and Dec. 31, 2013, Xcel Energy Inc. and its subsidiaries had no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy Inc.:

(Millions of Dollars)	Sept. 30, 2014	Dec. 31, 2013
Guarantees issued and outstanding	$14.6	$19.4
Current exposure under these guarantees	0.2	0.3
Bonds with indemnity protection	32.1	32.1

Indemnification Agreements

In connection with the sale of certain Texas electric transmission assets to Sharyland Distribution and Transmission Services, LLC in 2013, SPS agreed to indemnify the purchaser for losses arising out of any breach of the representations, warranties and covenants under the related asset purchase agreement and for losses arising out of certain other matters, including pre-closing liabilities. SPS' indemnification obligation is capped at $37.1 million, in the aggregate. The indemnification provisions for most representations and warranties expire in December 2014. The remaining representations and warranties, which relate to due organization and transaction authorization, survive indefinitely. As of Sept. 30, 2014 and Dec. 31, 2013, SPS has recorded a $0.4 million liability related to this indemnity.

Xcel Energy Inc. and its subsidiaries provide indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including corporate existence, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of duration and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

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Environmental Contingencies

Ashland Manufactured Gas Plant (MGP) Site — NSP-Wisconsin has been named a potentially responsible party (PRP) for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The U.S. Environmental Protection Agency (EPA) issued its Record of Decision (ROD) in 2010, which describes the preferred remedy the EPA has selected for the cleanup of the Ashland site. For the Sediments at the Ashland Site, the ROD preferred remedy is a hybrid remedy involving both dry excavation and wet conventional dredging methodologies (the Hybrid Remedy). The ROD also identifies the possibility of a wet conventional dredging only remedy for the Sediments (the Wet Dredge), contingent upon the completion of a successful Wet Dredge pilot study.

In 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future remediation at the Ashland site. As a result of settlement negotiations with NSP-Wisconsin, the EPA agreed to segment the Ashland site into separate areas. The first area (Phase I Project Area) includes soil and groundwater in Kreher Park and the Upper Bluff. The second area includes the Sediments.

In October 2012, a settlement among the EPA, the Wisconsin Department of Natural Resources, the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin was approved by the U.S. District Court for the Western District of Wisconsin. This settlement resolves claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the settlement, NSP-Wisconsin agreed to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. Demolition activities occurred at the Ashland site in 2013. The final design for the soil, including excavation and treatment, as well as containment wall remedies was submitted to the EPA in April 2014 and work commenced in May 2014. A preliminary design for the groundwater remedy was also submitted to the EPA in April 2014 and those activities are expected to commence in 2015. Based on these updated designs, the cost estimate for the cleanup of the Phase I Project Area is approximately $52 million, of which approximately $21 million has already been spent. The settlement also resolves claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project Area and the Sediments. Fieldwork to address the Phase I Project Area at the Ashland site began at the end of 2012 and continues.

Negotiations are ongoing between the EPA and NSP-Wisconsin regarding who will pay for or perform the cleanup of the Sediments and what remedy will be implemented at the site to address the Sediments. It is NSP-Wisconsin's view that the Hybrid Remedy is not safe or feasible to implement. The EPA's ROD for the Ashland site includes estimates that the cost of the Hybrid Remedy is between $63 million and $77 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower. In November 2013, NSP-Wisconsin submitted a revised Wet Dredge pilot study work plan proposal to the EPA. In May 2014, NSP-Wisconsin entered into a final administrative order on consent for the Wet Dredge pilot study with the EPA. In September 2014, the EPA granted an extension of time to perform the pilot in 2015.

In August 2012, NSP-Wisconsin also filed litigation against other PRPs for their share of the cleanup costs for the Ashland site. Trial for this matter is scheduled for April 2015. Negotiations between the EPA, NSP-Wisconsin and several of the other PRPs regarding the PRPs' fair share of the cleanup costs for the Ashland site are also ongoing.

At Sept. 30, 2014 and Dec. 31, 2013, NSP-Wisconsin had recorded a liability of $106.9 million and $104.6 million, respectively, for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $25.4 million and $25.2 million, respectively, was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, potential contributions by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

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NSP-Wisconsin has deferred the estimated site remediation costs, as a regulatory asset, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by 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 retail rate case process. Under an existing PSCW policy, utilities have recovered remediation costs for MGPs in natural gas rates, amortized over a four- to six-year period. The PSCW historically has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation.

In the 2013 rate case decision, the PSCW recognized the potential magnitude of the future liability for the cleanup at the Ashland site and granted an exception to its existing policy at the request of NSP-Wisconsin. The elements of this exception include: (1) approval to begin recovery of estimated Phase 1 Project costs beginning on Jan. 1, 2013; (2) approval to amortize these estimated costs over a ten-year period; and (3) approval to apply a three percent carrying cost to the unamortized regulatory asset. In the 2014 rate case decision, the PSCW continued the cost recovery treatment with respect to the 2013 and 2014 cleanup costs for the Phase I Project Area. The PSCW determined the timing of the cleanup of the Sediments was uncertain and declined NSP-Wisconsin’s request to begin cost recovery for this portion of the cleanup in 2014 rates. However, the PSCW allowed NSP-Wisconsin to increase its 2014 amortization expense related to the cleanup by an additional $1.1 million to offset the need for a rate decrease for the natural gas utility.

Environmental Requirements

Water and waste

Federal Clean Water Act (CWA) Effluent Limitations Guidelines (ELG) — In June 2013, the EPA published a proposed ELG rule for power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters as well as utility-owned landfills that receive coal combustion residuals. The final rule is now expected in September 2015. Under the current proposed rule, facilities would need to comply as soon as possible after July 2017, but no later than July 2022. The impact of this rule on Xcel Energy is uncertain at this time.

Federal CWA Section 316(b) — Section 316(b) of the federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse environmental impacts to aquatic species. The EPA published the final 316(b) rule in August 2014. The rule prescribes technology for protecting fish that get stuck on plant intake screens (known as impingement) and describes a process for site-specific determinations by each state for sites that must protect the small aquatic organisms that pass through the intake screens into the plant cooling systems (known as entrainment). For Xcel Energy, these requirements will primarily impact plants within the NSP-Minnesota service territory. The timing of compliance with the requirements will vary from plant-to-plant since the new rule does not have a final compliance deadline. Xcel Energy estimates the likely cost for complying with impingement requirements is approximately $46 million with the majority needed for NSP-Minnesota. Xcel Energy believes at least four NSP-Minnesota plants could be required by state regulators to make improvements to reduce entrainment. The exact cost of the entrainment improvements is uncertain, but could be up to $180 million depending on the outcome of certain entrainment studies and cost-benefit analyses. Xcel Energy anticipates these costs will be fully recoverable in rates.

Federal CWA Waters of the United States Rule — In April 2014, the EPA and the U.S. Army Corps of Engineers issued a proposed rule that significantly expands the types of water bodies regulated under the CWA. If finalized as proposed, this rule could delay the siting of new pipelines, transmission lines and distribution lines, increase project costs and expand permitting and reporting requirements. The ultimate impact of the proposed rule will depend on the specific requirements of the final rule and cannot be determined at this time. A final rule is not anticipated before the first quarter of 2015.

Air

EPA Greenhouse Gas (GHG) Permitting — In 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which were applicable to the construction of new power plants or power plant modifications that increase emissions above a certain threshold. These rules were upheld by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit), but in June 2014 the U.S. Supreme Court reversed the EPA's GHG emission thresholds for this program. The Supreme Court decided the EPA could not adopt GHG thresholds that would require permitting for new and modified large stationary sources. However, the Supreme Court also decided if a new or modified stationary source becomes subject to the permitting requirements by exceeding emission thresholds for other pollutants, then GHG emissions may be evaluated as part of the permitting process. Xcel Energy is unable to determine the cost of compliance with these new EPA requirements as it is not clear whether these requirements will apply to future changes at Xcel Energy's power plants.

GHG Emission Standard for Existing Sources — In June 2014, the EPA published its proposed rule on GHG emission standards for existing power plants. Comments are due to the EPA on Dec. 1, 2014 and a final rule is anticipated in June 2015. Following adoption of the final rule, states must develop implementation plans by June 2016, with the possibility of an extension to June 2017 (June 2018 if submitting a joint plan with other states). Among other things, the proposed rule would require that state plans include enforceable measures to ensure emissions from existing power plants in the state achieve the EPA's state-specific interim (2020-2029) and final (2030 and thereafter) emission performance targets. The plan will likely require additional emission reductions in states in which Xcel Energy operates. It is not possible to evaluate the impact of existing source standards until the EPA promulgates a final rule and states have adopted their applicable state plans.

GHG New Source Performance Standard (NSPS) Proposal — In January 2014, the EPA re-proposed a GHG NSPS for newly constructed power plants which would set performance standards (maximum carbon dioxide emission rates) for coal- and natural gas-fired power plants. For coal power plants, the NSPS requires an emissions level equivalent to partial carbon capture and storage (CCS) technology; for gas-fired power plants, the NSPS reflects emissions levels from combined cycle technology with no CCS. The EPA continues to propose that the NSPS not apply to modified or reconstructed existing power plants. In addition, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. It is not possible to evaluate the impact of the re-proposed NSPS until its final requirements are known.

GHG NSPS for Modified and Reconstructed Power Plants — In June 2014, the EPA published a proposed NSPS that would apply to GHG emissions from power plants that are modified or reconstructed. A final rule is anticipated in June 2015. A modification is a change to an existing source that increases the maximum achievable hourly rate of emissions. A reconstruction involves the replacement of components at a unit to the extent that the capital cost of the new components exceeds 50 percent of the capital cost of an entirely new comparable unit. The proposed standards would not require installation of CCS technology. Instead, the proposed standard for coal-fired power plants would require a combination of best operating practices and equipment upgrades. The proposal for gas-fired power plants would require emissions standards based on efficient combined cycle technology. It is not possible to evaluate the impact of these proposed standards until the final requirements are known. In addition, it is not clear whether these requirements, once adopted, would apply to future changes at Xcel Energy's power plants.

Cross-State Air Pollution Rule (CSAPR) — In 2011, the EPA issued the CSAPR to address long range transport of particulate matter (PM) and ozone by requiring reductions in sulfur dioxide (SO_2) and nitrous oxide (NOx) from utilities in the eastern half of the United States. For Xcel Energy, the rule would apply in Minnesota, Wisconsin and Texas. The CSAPR set more stringent requirements than the proposed Clean Air Transport Rule and requires plants in Texas to reduce their SO_2 and annual NOx emissions. The rule also creates an emissions trading program.

In August 2012, the D.C. Circuit vacated the CSAPR and remanded it back to the EPA. The D.C. Circuit stated the EPA must continue administering the Clean Air Interstate Rule (CAIR) pending adoption of a valid replacement. In April 2014, the U.S. Supreme Court reversed and remanded the case to the D.C. Circuit. The Supreme Court held that the EPA's rule design did not violate the Clean Air Act (CAA) and that states had received adequate opportunity to develop their own plans. Because the D.C. Circuit overturned the CSAPR on two over-arching issues, there are many other issues the D.C. Circuit did not rule on that will now need to be considered on remand. In June 2014, the EPA filed a motion with the D.C. Circuit asking it to lift the stay of the CSAPR. The EPA requested the CSAPR's 2012 compliance obligations be imposed starting in January 2015. The D.C. Circuit granted the EPA's motion in October 2014. In addition, the D.C. Circuit set a briefing schedule and plans to hear arguments on the remaining issues in the case in March 2015.

Multiple changes to the SPS system since 2011 will substantially reduce estimated costs of complying with the CSAPR. These include the addition of 700 MW of wind power, the construction of Jones Units 3 and 4 to meet reserve requirements and provide quick start capability, reduced wholesale load and new PPAs, installation of NOx combustion controls on Tolk Units 1 and 2 and completion of certain transmission projects. As a result, SPS estimates compliance with the CSAPR in 2015 will cost approximately $7 million.

NSP-Minnesota can operate within its CSAPR emission allowance allocations, particularly given the cessation of coal operations at Black Dog Units 3 and 4 in early 2015. NSP-Wisconsin can operate within its CSAPR emission allowance allocation for SO_2 due to cessation of coal combustion at Bay Front Unit 5. NSP-Wisconsin anticipates compliance with the CSAPR for NOx in 2015 through operational changes or allowance purchases. CSAPR compliance in 2015 is not expected to have a material impact on the results of operations, financial position or cash flows.

The EPA will begin to administer the CSAPR in 2015, which will replace the CAIR. In 2014, Xcel Energy expects to comply with the CAIR as described below.

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CAIR — In 2005, the EPA issued the CAIR to further regulate SO_2 and NOx emissions. The CAIR applies to Texas and Wisconsin. The CAIR does not currently apply to Minnesota.

Under the CAIR's cap and trade structure, companies can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. NSP-Wisconsin purchased allowances in 2012 and 2013 and plans to continue to purchase allowances in 2014 to comply with the CAIR. In the SPS region, installation of low-NOx combustion control technology was completed in 2012 on Tolk Unit 1 and in 2014 on Tolk Unit 2. These installations will reduce or eliminate SPS' need to purchase NOx emission allowances. At Sept. 30, 2014, the estimated annual CAIR NOx allowance cost for Xcel Energy did not have a material impact on the results of operations, financial position or cash flows. SPS has sufficient SO_2 allowances to comply with the CAIR through 2015.

Regional Haze Rules — The regional haze program is designed to address widespread, regionally homogeneous haze that results from emissions from a multitude of sources. In 2005, the EPA amended the best available retrofit technology (BART) requirements of its regional haze rules, which require the installation and operation of emission controls for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas. In their first regional haze state implementation plan (SIP), Colorado, Minnesota and Texas identified the Xcel Energy facilities that will have to reduce SO_2, NOx and PM emissions under BART and set emissions limits for those facilities.

PSCo

In 2011, the Colorado Air Quality Control Commission approved a SIP (the Colorado SIP) that included the CACJA emission reduction plan as satisfying regional haze requirements for the facilities included in the CACJA plan. In addition, the Colorado SIP included a BART determination for Comanche Units 1 and 2. The EPA approved the Colorado SIP in 2012. Emission controls at the Hayden and Pawnee plants are projected to cost $360.5 million and are expected to be installed between 2014 and 2017. PSCo anticipates these costs will be fully recoverable in rates.

In March 2013, WildEarth Guardians petitioned the U.S. Court of Appeals for the 10th Circuit to review the EPA's decision approving the Colorado SIP. WildEarth Guardians has stated it will challenge the BART determination made for Comanche Units 1 and 2. In comments before the EPA, WildEarth Guardians urged that current emission limitations be made more stringent or that selective catalytic reduction (SCR) be added to the units. In September 2014, the EPA filed a request with the Court to remand the case to the EPA for additional explanation of the EPA's decision approving the BART determination for Comanche Units 1 and 2. On Oct. 6, 2014, the Court granted the EPA's request and vacated the current briefing schedule. The EPA must provide a status update to the Court within 30 days.

In 2010, two environmental groups petitioned the U.S. Department of the Interior (DOI) to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege the Colorado BART rule is inadequate to satisfy the CAA mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota

In 2009, the Minnesota Pollution Control Agency (MPCA) approved a SIP (the Minnesota SIP) and submitted it to the EPA for approval. The MPCA's source-specific BART limits for Sherco Units 1 and 2 require combustion controls for NOx and scrubber upgrades for SO_2. The MPCA concluded SCRs should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The combustion controls have been installed and the scrubber upgrades, to be completed by January 2015, are underway. These emission controls are projected to cost approximately $50 million, of which $45.8 million has already been spent. NSP-Minnesota anticipates these costs will be fully recoverable in rates.

After the CSAPR was adopted in 2011, the MPCA supplemented its Minnesota SIP, determining that CSAPR meets BART requirements, but also implementing its source-specific BART determination for Sherco Units 1 and 2 from the 2009 Minnesota SIP. In June 2012, the EPA approved the Minnesota SIP for electric generating units (EGUs) and also approved the source-specific emission limits for Sherco Units 1 and 2 as strengthening the Minnesota SIP, but avoided characterizing them as BART limits.

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In August 2012, the National Parks Conservation Association, Sierra Club, Voyageurs National Park Association, Friends of the Boundary Waters Wilderness, Minnesota Center for Environmental Advocacy and Fresh Energy appealed the EPA's approval of the Minnesota SIP to the U.S. Court of Appeals for the Eighth Circuit (Eighth Circuit). NSP-Minnesota and other regulated parties were denied intervention. In June 2013, the Eighth Circuit ordered this case to be held in abeyance until the U.S. Supreme Court decided the CSAPR case. In October 2014, the Eighth Circuit set a briefing schedule. The case will be briefed by early 2015. An argument date has not been set. If this litigation ultimately results in further EPA proceedings concerning the Minnesota SIP, such proceedings may consider whether SCRs should be required for Sherco Units 1 and 2.

SPS
Harrington Units 1 and 2 are potentially subject to BART. Texas developed a SIP (the Texas SIP) that finds the CAIR equal to BART for EGUs. As a result, no additional controls beyond CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs. It is not yet known how the U.S. Supreme Court's April 2014 decision on the CSAPR, or the D.C. Circuit's decision to lift its stay of the CSAPR, may impact the EPA's approval of the BART requirements in the Texas SIP.

In May 2014, the EPA issued a request for information under the CAA related to SO_2 control equipment at Tolk Units 1 and 2. The EPA stated it is conducting an analysis of the cost and feasibility of SO_2 controls on certain sources, including the Tolk facility, as part of its review of the Texas SIP. The EPA has preliminarily identified Tolk as a contributor to haze in the Wichita Mountains Wildlife Refuge in Oklahoma, and is planning further analysis of SO_2 control options. The EPA plans to make a proposal in November 2014 that could include SO_2 emission controls at Tolk and anticipates issuing a final decision in August 2015. The costs and timing of potential additional SO_2 controls at Tolk are dependent on the EPA's proposal and final decision, neither of which is yet known.

Reasonably Attributable Visibility Impairment (RAVI) — RAVI is intended to address observable impairment from a specific source such as distinct, identifiable plumes from a source's stack to a national park. In 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota's Sherco Units 1 and 2. The EPA is required to make its own determination whether there is RAVI-type impairment in these parks and examine which sources may cause or contribute to any RAVI impact that is identified. After studying the national parks and evaluating multiple sources, if the EPA finds that Sherco Units 1 and 2 cause or contribute to RAVI in the national parks, the EPA would then evaluate whether the level of controls required by the MPCA is appropriate. The EPA has stated it plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program.

In December 2012, a lawsuit against the EPA was filed in the U.S. District Court for the District of Minnesota by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyageurs National Park Association, Fresh Energy and Sierra Club. The lawsuit alleges the EPA has failed to perform a nondiscretionary duty to determine BART for Sherco Units 1 and 2 under the RAVI program. The EPA filed an answer denying the allegations. The District Court denied NSP-Minnesota's motion to intervene in July 2013. NSP-Minnesota appealed this decision to the Eighth Circuit, which on July 23, 2014, reversed the District Court and found that NSP-Minnesota has standing and a right to intervene.

In June 2014, the EPA and the plaintiffs lodged a consent decree with the District Court. The consent decree recites it will be subject to public comment. The EPA will then evaluate comments and determine whether to enter the consent decree with the District Court. The consent decree establishes a schedule whereby the EPA would issue a proposal on Feb. 27, 2015, determining whether visibility impairment in the national parks is reasonably attributable to Sherco Units 1 and 2. If the EPA determines that it is, the consent decree requires the EPA to make a final RAVI BART determination for these units by Aug. 31, 2015. If the EPA determines that it is not, the EPA would not determine

BART for Sherco Units 1 and 2. NSP-Minnesota filed comments opposing the proposed consent decree and will object to its entry given NSP-Minnesota's right to intervene in the litigation and thus participate in the negotiation of any purported settlement of the case.

Revisions to National Ambient Air Quality Standards (NAAQS) for PM — In December 2012, the EPA lowered the primary health-based NAAQS for annual average fine PM and retained the current daily standard for fine PM. In areas where Xcel Energy operates power plants, current monitored air concentrations are below the level of the final annual primary standard. In August 2014, EPA issued its proposed designations, which did not include areas in any states in which Xcel Energy operates. The EPA is expected to finalize its designation of non-compliant locations by December 2014. States would then study the sources of the nonattainment and make emission reduction plans to attain the standards. It is not possible to evaluate the impact of this regulation further until the final designations have been made.

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Legal Contingencies

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss. For current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Xcel Energy’s financial statements. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota’s decision to terminate the agreements was based in part on enXco’s nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. In May 2011 enXco filed a lawsuit in the U.S. District Court in Minnesota seeking approximately $240 million for an alleged breach of contract. In April 2013, the U.S. District Court granted NSP-Minnesota’s motion for summary judgment and entered judgment in its favor. enXco subsequently appealed to the Eighth Circuit, which affirmed the U.S. District Court’s decision in July 2014. enXco has elected not to challenge this decision within the required time period which brings this matter to a close.

Exelon Wind (formerly John Deere Wind) Complaint — Several lawsuits in Texas state and federal courts and regulatory proceedings have arisen out of a dispute concerning SPS’ payments for energy and capacity produced from the Exelon Wind subsidiaries’ projects. There are two main areas of dispute. First, Exelon Wind claims that it established legally enforceable obligations (LEOs) for each of its 12 wind facilities in 2005 through 2008 that require SPS to buy power based on SPS’ forecasted avoided cost as determined in 2005 through 2008. Although SPS has refused to accept Exelon Wind’s LEOs, SPS accepts that it must take energy from Exelon Wind under SPS’ PUCT-approved Qualifying Facilities (QF) Tariff. Second, Exelon Wind has raised various challenges to SPS’ PUCT-approved QF Tariff, which became effective in August 2010. The state and federal lawsuits and regulatory proceedings are in various stages of litigation. On Sept. 8, 2014, the Fifth Circuit Court of Appeals (Fifth Circuit) ruled that federal courts do not have jurisdiction to hear Exelon Wind’s challenge to the PUCT’s decision that Exelon Wind is ineligible to establish LEOs for the six wind facilities that were the subject of the PUCT’s order. The Fifth Circuit also ruled that the PUCT’s requirement that only QF’s providing firm energy are eligible to establish LEOs is valid. Exelon Wind filed a motion for rehearing with the Fifth Circuit on Sept. 22, 2014. On Oct. 10, 2014, the Fifth Circuit denied Exelon Wind’s motion for rehearing. SPS believes the likelihood of loss in these lawsuits and proceedings is remote based primarily on existing case law and while it is not possible to estimate the amount or range of reasonably possible loss in the event of an adverse outcome, SPS believes such loss would not be material based upon its belief that it would be permitted to recover such costs, if needed, through its various fuel clause mechanisms. No accrual has been recorded for this matter.

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there were unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for December 2000 through June 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific

Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the Ninth Circuit Court of Appeals (Ninth Circuit).

In an order issued in August 2007, the Ninth Circuit remanded the proceeding back to the FERC and indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Ninth Circuit denied a petition for rehearing in April 2009, and the mandate was issued.

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The FERC issued an order on remand establishing principles for the review proceeding in October 2011. In September 2012, the City of Seattle filed its direct case against PSCo and other Pacific Northwest sellers claiming refunds for the period January 2000 through June 2001. The City of Seattle indicated that for the period June 2000 through June 2001 PSCo had sales to the City of Seattle of approximately $50 million. The City of Seattle did not identify specific instances of unlawful market activity by PSCo, but rather based its claim for refunds on market dysfunction in the Western markets. PSCo submitted its answering case in December 2012.

In April 2013, the FERC issued an order on rehearing. The FERC confirmed that the City of Seattle would be able to attempt to obtain refunds back from January 2000, but reaffirmed the transaction-specific standard that the City of Seattle and other complainants would have to comply with to obtain refunds. In addition, the FERC rejected the imposition of any market-wide remedies. Although the FERC order on rehearing established the period for which the City of Seattle could seek refunds as January 2000 through June 2001, it is unclear what claim the City of Seattle has against PSCo prior to June 2000. In the proceeding, the City of Seattle does not allege specific misconduct or tariff violations by PSCo but instead asserts generally that the rates charged by PSCo and other sellers were excessive.

A hearing in this case was held before a FERC ALJ and concluded in October 2013. On March 28, 2014, the FERC ALJ issued an initial decision which rejected all of the City of Seattle’s claims against PSCo and other respondents. With respect to the period Jan. 1, 2000 through Dec. 24, 2000, the FERC ALJ rejected the City of Seattle’s assertion that any of the sales made to the City of Seattle resulted in an excessive burden to the City of Seattle, the applicable legal standard for the City of Seattle’s challenges during this period. With respect to the period Dec. 25, 2000 through June 20, 2001, the FERC ALJ concluded that the City of Seattle had failed to establish a causal link between any contracts and any claimed unlawful market activity, the standard required by the FERC in its remand order. The City of Seattle contested the FERC ALJ’s initial decision by filing a brief on exceptions to the FERC. PSCo filed a brief answering the City of Seattle’s exception. This matter is now pending a decision by the FERC.

Preliminary calculations of the City of Seattle’s claim for refunds from PSCo are approximately $28 million excluding interest. PSCo has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, PSCo is currently unable to estimate the amount or range of reasonably possible loss in the event of an adverse outcome of this matter. In making this assessment, PSCo considered two factors. First, notwithstanding PSCo’s view that the City of Seattle has failed to apply the standard that the FERC has established in this proceeding, and the recognition that this case raises a novel issue and the FERC’s standard has been challenged on appeal to the Ninth Circuit, the outcome of such an appeal cannot be predicted with any certainty. Second, PSCo would expect to make equitable arguments against refunds even if the City of Seattle were to establish that it was overcharged for transactions. If a loss were sustained, PSCo would attempt to recover those losses from other PRPs. No accrual has been recorded for this matter.

Biomass Fuel Handling Reimbursement — NSP-Minnesota has a PPA through which it procures energy from Fibrominn, LLC (Fibrominn). Under this agreement, NSP-Minnesota is charged for certain costs of transporting biomass fuels that are delivered to Fibrominn’s generation facility. Fibrominn has demanded additional cost reimbursement for certain transportation costs incurred since 2007, as well as reimbursement for similar costs in future periods. Fibrominn claims that it is entitled to reimbursement from NSP-Minnesota for past transportation costs of approximately $20 million. NSP-Minnesota has evaluated Fibrominn’s claim and based on the terms of the PPA with Fibrominn and its current understanding of the facts, NSP-Minnesota disputes the validity of Fibrominn’s claim, on the ground that, among other things, it seeks to impose contractual obligations on NSP-Minnesota that are neither supported by the terms nor the intent of the PPA. NSP-Minnesota has concluded that a loss is reasonably possible with respect to this matter; however, given the surrounding uncertainties, NSP-Minnesota is currently unable to determine the amount of reasonably possible loss. If a loss were sustained, NSP-Minnesota would attempt to recover these fuel-related costs in rates. No accrual has been recorded for this matter.

Nuclear Power Operations and Waste Disposal

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 DOE’s failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the United States and NSP-Minnesota. NSP-Minnesota sought contract damages in this lawsuit through Dec. 31, 2004. In September 2007, the Court awarded NSP-Minnesota $116.5 million in damages. In August 2007, NSP-Minnesota filed a second complaint; this lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008.

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In July 2011, the United States and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the United States to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, estimated to be an additional $100 million. In January 2014, the United States proposed, and NSP-Minnesota accepted, an extension to the settlement agreement which will allow NSP-Minnesota to recover spent fuel storage costs through 2016. The extension does not address costs for used fuel storage after 2016; such costs could be the subject of future litigation. NSP-Minnesota has received a total of $181.9 million of settlement proceeds as of Sept. 30, 2014. NSP-Minnesota's next claim submission, in the amount of $33.6 million, was filed May 15, 2014, for costs incurred in 2013. In August 2014, the DOE accepted the claim for $32.8 million and NSP-Minnesota expects to receive payment in November 2014. Amounts received from the installments, except for approved reductions such as legal costs, will be subsequently returned to customers through a reduction of future rate increases or credited through another regulatory mechanism.

7. Borrowings and Other Financing Instruments

Short-Term Borrowings

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit	$2,450	$2,450
Amount outstanding at period end	697	759
Average amount outstanding	730	481
Maximum amount outstanding	894	1,160
Weighted average interest rate, computed on a daily basis	0.33 %	0.31 %
Weighted average interest rate at period end	0.33	0.25

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At Sept. 30, 2014 and Dec. 31, 2013, there were $71.4 million and $47.8 million of letters of credit outstanding, respectively, under the credit facilities. The contract amounts of these letters of credit approximate their fair value and are subject to fees.

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit facilities. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

At Sept. 30, 2014, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility [a]	Drawn [b]	Available
Xcel Energy Inc.	$800.0	$436.0	$364.0

PSCo	700.0	259.5	440.5
NSP-Minnesota	500.0	23.9	476.1
SPS	300.0	41.0	259.0
NSP-Wisconsin	150.0	8.0	142.0
Total	$2,450.0	$768.4	$1,681.6

[a] These credit facilities have been amended to expire in October 2019.

[b] Includes outstanding commercial paper and letters of credit.

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All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at Sept. 30, 2014 and Dec. 31, 2013.

Amended Credit Agreements — On Oct. 14, 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an extension of maturity from July 2017 to October 2019. In addition, the borrowing limit for Xcel Energy Inc. has been increased to $1 billion from $800 million and the borrowing limit for SPS has been increased to $400 million from $300 million. As a result, the total borrowing limit under the amended credit agreements increased to $2.75 billion from $2.45 billion. The Eurodollar borrowing margins on these lines of credit range from 87.5 to 175 basis points per year based on applicable long-term credit ratings. The commitment fees, calculated on the unused portion of the lines of credit, range from 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc. and its utility subsidiaries, other than NSP-Wisconsin, have the right to request an extension of the revolving termination date for two additional one-year periods, and NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period, each subject to majority bank group approval.

Long-Term Borrowings and Other Financing Instruments

During the nine months ended Sept. 30, 2014, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March 2014, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044;
- In May 2014, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June 2014, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June 2014, NSP-Wisconsin issued $100 million of 3.30 percent first mortgage bonds due June 15, 2024.

In connection with SPS' issuance of $150 million of 3.30 percent first mortgage bonds due June 15, 2024, SPS issued $250 million of collateral 8.75 percent first mortgage bonds due Dec. 1, 2018 to the trustee under its senior unsecured indenture in order to secure its previously issued Series G Senior Notes, 8.75 percent due Dec. 1, 2018, equally and ratably with SPS' first mortgage bonds as required by the terms of such Series G Senior Notes.

Issuances of Common Stock — Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an at-the-market (ATM) program and received cash proceeds of $172.7 million net of $1.9 million in fees and commissions during the first six months of 2014. During the year ended Dec. 31, 2013, Xcel Energy Inc. issued approximately 7.7 million shares of common stock through this program and received cash proceeds of $222.7 million net of $2.7 million in fees and commissions. Xcel Energy completed its ATM program as of June 30, 2014. The proceeds from the issuances of common stock were used to repay short-term debt, infuse equity into the utility subsidiaries and for other general corporate purposes.

8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance.

The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with models using highly observable inputs.

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 valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per-share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Proper notice varies by fund and can range from daily with one or two days notice to annually with 90 days notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice, which is typically quarterly with 45-90 days notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy’s evaluation of its redemption rights, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

Electric commodity derivatives held by NSP-Minnesota may include transmission congestion instruments purchased from MISO, PJM Interconnection, LLC (PJM), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool, Inc. (SPP) and New York Independent System Operator, generally referred to as financial transmission rights (FTRs). Electric commodity derivatives held by SPS include FTRs purchased from SPP. FTRs purchased from a RTO are financial instruments that entitle or obligate the holder to monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of energy congestion, which is caused by overall transmission load and other transmission constraints. In addition to overall transmission load, congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. The valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management’s forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Non-trading monthly FTR settlements are included in the fuel and purchased energy cost recovery mechanisms as applicable in each jurisdiction, and therefore changes in the fair value of the yet to be settled portions of most FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of FTRs relative to the electric utility operations of NSP-Minnesota and SPS, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

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Non-Derivative Instruments Fair Value Measurements

The NRC requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and PI nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins. NSP-Minnesota uses the MPUC approved asset allocation for the escrow and investment targets by asset class for both the escrow and qualified trust.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning.

Unrealized gains for the nuclear decommissioning fund were $287.5 million and $240.3 million at Sept. 30, 2014 and Dec. 31, 2013, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $58.8 million and $58.5 million at Sept. 30, 2014 and Dec. 31, 2013, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at Sept. 30, 2014 and Dec. 31, 2013:

	Sept. 30, 2014				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$14,972	$14,972	$—	$—	$14,972
Commingled funds	469,608	—	471,388	—	471,388
International equity funds	78,812	—	85,856	—	85,856
Private equity investments	74,222	—	—	97,004	97,004
Real estate	45,075	—	—	63,973	63,973
Debt securities:					
Government securities	34,379	—	29,726	—	29,726
U.S. corporate bonds	80,196	—	79,248	—	79,248
International corporate bonds	17,696	—	17,613	—	17,613
Municipal bonds	235,751	—	240,907	—	240,907
Asset-backed securities	9,226	—	9,347	—	9,347
Mortgage-backed securities	23,554	—	23,696	—	23,696
Equity securities:					
Common stock	377,287	555,711	—	—	555,711
Total	$1,460,778	$570,683	$957,781	$160,977	$1,689,441

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $84.5 million of equity investments in unconsolidated subsidiaries and $43.0 million of miscellaneous investments.

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	Dec. 31, 2013				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund [(a)]					
Cash equivalents	$33,281	$33,281	$—	$—	$33,281
Commingled funds	457,986	—	452,227	—	452,227
International equity funds	78,812	—	81,671	—	81,671
Private equity investments	52,143	—	—	62,696	62,696
Real estate	45,564	—	—	57,368	57,368
Debt securities:					
Government securities	34,304	—	27,628	—	27,628
U.S. corporate bonds	80,275	—	83,538	—	83,538
International corporate bonds	15,025	—	15,358	—	15,358
Municipal bonds	241,112	—	232,016	—	232,016
Equity securities:					
Common stock	406,695	581,243	—	—	581,243
Total	$1,445,197	$614,524	$892,438	$120,064	$1,627,026

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $87.1 million of equity investments in unconsolidated subsidiaries and $41.9 million of miscellaneous investments.

The following tables present the changes in Level 3 nuclear decommissioning fund investments for the three and nine months ended Sept. 30, 2014 and 2013:

(Thousands of Dollars)	July 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2014
Private equity investments	$81,123	$11,125	$—	$4,756	$—	$97,004
Real estate	65,658	1,530	(5,876)	2,661	—	63,973
Total	$146,781	$12,655	$(5,876)	$7,417	$—	$160,977

(Thousands of Dollars)	July 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2013
Private equity investments	$45,590	$6,790	$—	$94	$—	$52,474
Real estate	38,140	11,288	—	1,928	—	51,356
Total	$83,730	$18,078	$—	$2,022	$—	$103,830

(Thousands of Dollars)	Jan. 1, 2014	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3	Sept. 30, 2014
Private equity investments	$62,696	$22,078	$—	$12,230	$—	$97,004
Real estate	57,368	5,386	(5,876)	7,095	—	63,973
Total	$120,064	$27,464	$(5,876)	$19,325	$—	$160,977

(Thousands of Dollars)	Jan. 1, 2013	Purchases	Settlements	Gains Recognized as Regulatory Liabilities	Transfers Out of Level 3 [(a)]	Sept. 30, 2013
Private equity investments	$33,250	$15,344	$—	$3,880	$—	$52,474
Real estate	39,074	18,106	(9,022)	3,198	—	51,356
Asset-backed securities	2,067	—	—	—	(2,067)	—
Mortgage-backed securities	30,209	—	—	—	(30,209)	—
Total	$104,600	$33,450	$(9,022)	$7,078	$(32,276)	$103,830

(a) Transfers out of Level 3 into Level 2 were principally due to diminished use of unobservable inputs that were previously significant to these fair value measurements.

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The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class, at Sept. 30, 2014:

(Thousands of Dollars)	Final Contractual Maturity Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$—	$—	$—	$29,726	$29,726
U.S. corporate bonds	303	15,878	62,985	82	79,248
International corporate bonds	—	4,266	13,347	—	17,613
Municipal bonds	807	34,188	41,744	164,168	240,907
Asset-backed securities	—	—	3,546	5,801	9,347
Mortgage-backed securities	—	—	—	23,696	23,696
Debt securities	$1,110	$54,332	$121,622	$223,473	$400,537

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to manage risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices.

Interest Rate Derivatives — Xcel Energy enters 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 an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At Sept. 30, 2014, accumulated other comprehensive losses related to interest rate derivatives included $2.4 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings, including forecasted amounts for any unsettled hedges.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and 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.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, natural gas for resale, FTRs, vehicle fuel and weather.

At Sept. 30, 2014, Xcel Energy had various vehicle fuel contracts designated as cash flow hedges extending through December 2016. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in other comprehensive income or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three and nine months ended Sept. 30, 2014 and 2013.

At Sept. 30, 2014, net gains related to commodity derivative cash flow hedges recorded as a component of accumulated other comprehensive losses included an immaterial amount of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

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The following table details the gross notional amounts of commodity forwards, options and FTRs at Sept. 30, 2014 and Dec. 31, 2013:

(Amounts in Thousands) [a][b]	Sept. 30, 2014	Dec. 31, 2013
Megawatt hours of electricity	74,912	58,423
Million British thermal units of natural gas	18,482	9,854
Gallons of vehicle fuel	332	482

[a] Amounts are not reflective of net positions in the underlying commodities.

[b] Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

The following tables detail the impact of derivative activity during the three and nine months ended Sept. 30, 2014 and 2013, on accumulated other comprehensive loss, regulatory assets and liabilities, and income:

	Three Months Ended Sept. 30, 2014				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$967 [a]	$—	$—
Vehicle fuel and other commodity	(69)	—	(16) [b]	—	—
Total	$(69)	$—	$951	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$(1,656) [c]
Electric commodity	—	(3,391)	—	6,629 [d]	—
Natural gas commodity	—	(2,455)	—	—	(209) [d]
Total	$—	$(5,846)	$—	$6,629	$(1,865)

	Nine Months Ended Sept. 30, 2014				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$2,869 [a]	$—	$—
Vehicle fuel and other commodity	(56)	—	(61) [b]	—	—
Total	$(56)	$—	$2,808	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$1,266 [c]
Electric commodity	—	(17,240)	—	(18,641) [d]	—

Natural gas commodity	—	13,603	—	(18,840) [e]	(5,575) [e]
Other commodity	—	—	—	—	643 [c]
Total	$—	$(3,637)	$—	$(37,481)	$(3,666)

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	Three Months Ended Sept. 30, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$829 (a)	$—	$—
Vehicle fuel and other commodity	36	—	(24) (b)	—	—
Total	$36	$—	$805	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$7,094 (c)
Electric commodity	—	921	—	(9,823) (d)	—
Natural gas commodity	—	(1,967)	—	—	12 (d)
Total	$—	$(1,046)	$—	$(9,823)	$7,106

	Nine Months Ended Sept. 30, 2013				
	Pre-Tax Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		Pre-Tax Gains (Losses) Recognized During the Period in Income
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	
Derivatives designated as cash flow hedges					
Interest rate	$—	$—	$3,140 (a)	$—	$—
Vehicle fuel and other commodity	(11)	—	(67) (b)	—	—
Total	$(11)	$—	$3,073	$—	$—
Other derivative instruments					
Commodity trading	$—	$—	$—	$—	$9,372 (c)
Electric commodity	—	61,314	—	(38,816) (d)	—
Natural gas commodity	—	(5,341)	—	9 (e)	(216) (d)
Total	$—	$55,973	$—	$(38,807)	$9,156

(a) Amounts are recorded to interest charges.

(b) Amounts are recorded to O&M expenses.

(c) Amounts are recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(d) Amounts are recorded to electric fuel and purchased power. These derivative settlement gain and loss amounts are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e) Amounts for the nine months ended Sept. 30, 2014 and 2013 included immaterial settlement losses on derivatives entered to mitigate natural gas price risk for electric generation, recorded to electric fuel and purchased power, subject to cost-recovery mechanisms and reclassified to a regulatory asset, as appropriate. The remaining derivative settlement gains and losses for the nine months ended Sept. 30, 2014 and 2013 relate to natural gas operations and are recorded to cost of natural gas sold and transported. These gains and losses are subject to cost-recovery mechanisms and reclassified out of income to a regulatory asset or liability, as appropriate.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2014 and 2013. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

Consideration of Credit Risk and Concentrations — Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivative contracts prior to settlement, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of unsettled commodity derivatives presented in the consolidated balance sheets.

Xcel Energy Inc. and its subsidiaries employ 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. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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Xcel Energy’s utility subsidiaries’ most significant concentrations of credit risk with particular entities or industries are contracts with counterparties to their wholesale, trading and non-trading commodity and transmission activities. At Sept. 30, 2014, four of Xcel Energy’s 10 most significant counterparties for these activities, comprising $48.8 million or 16 percent of this credit exposure, had investment grade credit ratings from Standard & Poor’s Ratings Services, Moody’s Investor Services (Moody’s) or Fitch Ratings. The remaining six significant counterparties, comprising $75.0 million or 25 percent of this credit exposure, were not rated by these agencies, but based on Xcel Energy’s internal analysis, had credit quality consistent with investment grade. All 10 of these significant counterparties are RTOs, municipal or cooperative electric entities or other utilities.

Credit Related Contingent Features — Contract provisions for derivative instruments that the utility subsidiaries enter, including those recorded to the consolidated balance sheet at fair value, as well as those accounted for as normal purchase-normal sale contracts and therefore not reflected on the balance sheet, may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. At Sept. 30, 2014, there were no derivative instruments in a liability position that would have required the posting of collateral or settlement of applicable outstanding contracts if the credit ratings of Xcel Energy Inc.’s utility subsidiaries were downgraded below investment grade. If the credit ratings of Xcel Energy Inc.’s utility subsidiaries were downgraded below investment grade at Dec. 31, 2013, derivative instruments reflected in a $1.4 million gross liability position on the consolidated balance sheets at Dec. 31, 2013, would have required Xcel Energy Inc.’s utility subsidiaries to post collateral or settle applicable outstanding contracts, including other contracts subject to master netting agreements, which would have resulted in payments of $1.4 million. At Sept. 30, 2014 and Dec. 31, 2013, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary’s ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of Sept. 30, 2014 and Dec. 31, 2013.

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Recurring Fair Value Measurements — The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Sept. 30, 2014:

	Sept. 30, 2014					
	Fair Value			Fair Value	Counterparty	
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total	Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$4	$—	$4	$(3)	$1
Other derivative instruments:						
Commodity trading	—	18,912	4,609	23,521	(5,395)	18,126
Electric commodity	—	—	86,708	86,708	(17,685)	69,023
Natural gas commodity	—	10,051	—	10,051	(74)	9,977
Total current derivative assets	$—	$28,967	$91,317	$120,284	$(23,157)	97,127
PPAs [a]						23,527
Current derivative instruments						$120,654
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Other derivative instruments:						
Commodity trading	$—	$13,269	$—	$13,269	$(2,408)	$10,861
Total noncurrent derivative assets	$—	$13,269	$—	$13,269	$(2,408)	10,861
PPAs [a]						42,716
Noncurrent derivative instruments						$53,577
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$3	$—	$3	$(3)	$—
Other derivative instruments:						
Commodity trading	—	9,759	—	9,759	(9,337)	422
Electric commodity	—	—	17,685	17,685	(17,685)	—
Natural gas commodity	—	74	—	74	(74)	—
Total current derivative liabilities	$—	$9,836	$17,685	$27,521	$(27,099)	422
PPAs [a]						22,502
Current derivative instruments						$22,924
Noncurrent derivative liabilities						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$5	$—	$5	$—	$5
Other derivative instruments:						
Commodity trading	—	3,066	—	3,066	(2,408)	658
Natural gas commodity	—	71	—	71	—	71
Total noncurrent derivative liabilities	$—	$3,142	$—	$3,142	$(2,408)	734
PPAs [a]						186,711
Noncurrent derivative instruments						$187,445

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs 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.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Sept. 30, 2014. At Sept. 30, 2014, derivative assets and liabilities include no obligations to return cash collateral and the rights to reclaim cash collateral of $3.9 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents for each of the fair value hierarchy levels, Xcel Energy's derivative assets and liabilities measured at fair value on a recurring basis at Dec. 31, 2013:

(Thousands of Dollars)	Dec. 31, 2013 Fair Value Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting [b]	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$88	$—	$88	$—	$88
Other derivative instruments:						
Commodity trading	—	20,610	1,167	21,777	(7,994)	13,783
Electric commodity	—	—	47,112	47,112	(8,210)	38,902
Natural gas commodity	—	5,906	—	5,906	—	5,906
Total current derivative assets	$—	$26,604	$48,279	$74,883	$(16,204)	58,679
PPAs [a]						33,028
Current derivative instruments						$91,707
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$—	$29	$—	$29	$(16)	$13
Other derivative instruments:						
Commodity trading	—	32,074	3,395	35,469	(9,071)	26,398
Total noncurrent derivative assets	$—	$32,103	$3,395	$35,498	$(9,087)	26,411
PPAs [a]						58,431
Noncurrent derivative instruments						$84,842
Current derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$10,546	$1,804	$12,350	$(12,002)	$348
Electric commodity	—	—	8,210	8,210	(8,210)	—
Total current derivative liabilities	$—	$10,546	$10,014	$20,560	$(20,212)	348
PPAs [a]						23,034
Current derivative instruments						$23,382
Noncurrent derivative liabilities						
Other derivative instruments:						
Commodity trading	$—	$14,382	$—	$14,382	$(9,087)	$5,295
Total noncurrent derivative liabilities	$—	$14,382	$—	$14,382	$(9,087)	5,295
PPAs [a]						203,929
Noncurrent derivative instruments						$209,224

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term PPAs 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.

(b) Xcel Energy nets derivative instruments and related collateral in its consolidated balance sheet when supported by a legally enforceable master netting agreement, and all derivative instruments and related collateral amounts were subject to master netting agreements at Dec. 31, 2013. At Dec. 31, 2013, derivative assets and liabilities include obligations to return cash collateral of $0.2 million and the rights to reclaim cash collateral of $4.2 million. The counterparty netting amounts presented exclude settlement receivables and payables and non-derivative amounts that may be subject to the same master netting agreements.

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The following table presents the changes in Level 3 commodity derivatives for the three and nine months ended Sept. 30, 2014 and 2013:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2014	2013
Balance at July 1	$105,394	$47,218
Purchases	5,588	155
Settlements	(20,032)	(9,342)
Transfers out of Level 3	(1,093)	—
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	1,480	4,008
Losses recognized as regulatory assets and liabilities	(17,705)	(571)
Balance at Sept. 30	$73,632	$41,468

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2014	2013
Balance at Jan. 1	$41,660	$16,649
Purchases	126,752	51,541
Settlements	(107,451)	(30,294)
Transfers out of Level 3	(1,093)	—
Net transactions recorded during the period:		
Gains recognized in earnings [(a)]	8,917	3,729
Gains (losses) recognized as regulatory assets and liabilities	4,847	(157)
Balance at Sept. 30	$73,632	$41,468

[(a)] These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. The transfer of amounts from Level 3 to Level 2 in the three and nine months ended Sept. 30, 2014 was due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period. There were no transfers of amounts between levels for derivative instruments for the three and nine months ended Sept. 30, 2013.

Fair Value of Long-Term Debt

As of Sept. 30, 2014 and Dec. 31, 2013, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Sept. 30, 2014		Dec. 31, 2013	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$11,759,226	$12,990,348	$11,191,517	$11,878,643

The fair value of Xcel Energy’s long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of Sept. 30, 2014 and Dec. 31, 2013, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2.

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9. Other Income (Expense), Net

Other income (expense), net consisted of the following:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Thousands of Dollars)	2014	2013	2014	2013
Interest income	$1,139	$1,304	$6,324	$7,615
Other nonoperating income	682	739	3,042	2,494
Insurance policy expense	(417)	(2,386)	(4,663)	(5,932)
Other nonoperating expense	—	(61)	(16)	(246)
Other income (expense), net	$1,404	$(404)	$4,687	$3,931

10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits and distributes electricity primarily in portions of Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $84.5 million and $87.1 million as of Sept. 30, 2014 and Dec. 31, 2013, respectively, included in the regulated natural gas utility segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	All Other

	Regulated Electric	Regulated Natural Gas		Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2014					
Operating revenues from external customers	$2,616,351	$236,649	$16,807	$—	$2,869,807
Intersegment revenues	472	597	—	(1,069)	—
Total revenues	$2,616,823	$237,246	$16,807	$(1,069)	$2,869,807
Net income	$360,656	$3,996	$3,930	$—	$368,582

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2013					
Operating revenues from external customers	$2,599,925	$205,358	$17,055	$—	$2,822,338
Intersegment revenues	346	1,106	—	(1,452)	—
Total revenues	$2,600,271	$206,464	$17,055	$(1,452)	$2,822,338
Net income (loss)	$365,156	$(174)	$(230)	$—	$364,752

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2014					
Operating revenues from external customers	$7,215,699	$1,485,464	$56,344	$—	$8,757,507
Intersegment revenues	1,262	4,967	—	(6,229)	—
Total revenues	$7,216,961	$1,490,431	$56,344	$(6,229)	$8,757,507
Net income (loss)	$731,766	$96,629	$(3,428)	$—	$824,967

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2013					
Operating revenues from external customers	$6,911,998	$1,216,275	$55,827	$—	$8,184,100
Intersegment revenues	955	2,163	—	(3,118)	—
Total revenues	$6,912,953	$1,218,438	$55,827	$(3,118)	$8,184,100
Net income (loss)	$740,347	$80,698	$(22,866)	$—	$798,179

11. Earnings Per Share

Basic earnings per share (EPS) was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents) were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated using the treasury stock method.

Common Stock Equivalents — Xcel Energy Inc. currently has common stock equivalents related to certain equity awards in share-based compensation arrangements.

Common stock equivalents causing dilutive impact to EPS include commitments to issue common stock related to time based equity compensation awards and time based employer matching contributions to certain 401(k) plan participants. In October 2013, Xcel Energy determined that it would settle 401(k) employer matching contributions in cash instead of common stock for substantially all of its employees. Share-based compensation accounting for the impacted employee groups ceased in October 2013, and corresponding expense amounts recorded to equity were reclassified to a liability for expected cash settlements.

Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due to certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

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The dilutive impact of common stock equivalents affecting EPS was as follows:

	Three Months Ended Sept. 30, 2014			Three Months Ended Sept. 30, 2013		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$368,582			$364,752		
Basic EPS:						
Earnings available to common shareholders	368,582	506,082	$0.73	364,752	498,149	$0.73
Effect of dilutive securities:						
Time based equity awards	—	283		—	492	
Diluted EPS:						
Earnings available to common shareholders	$368,582	506,365	$0.73	$364,752	498,641	$0.73

	Nine Months Ended Sept. 30, 2014			Nine Months Ended Sept. 30, 2013		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$824,967			$798,179		
Basic EPS:						
Earnings available to common shareholders	824,967	502,983	$1.64	798,179	495,256	$1.61
Effect of dilutive securities:						
Time based equity awards	—	230		—	511	
Diluted EPS:						
Earnings available to common shareholders	$824,967	503,213	$1.64	$798,179	495,767	$1.61

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended Sept. 30			
	2014	2013	2014	2013
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$22,086	$24,071	$864	$1,182
Interest cost	39,155	35,173	8,507	8,417
Expected return on plan assets	(51,801)	(49,613)	(8,489)	(8,253)
Amortization of transition obligation	—	—	—	206
Amortization of prior service (credit) cost	(437)	1,468	(2,672)	(2,438)
Amortization of net loss	29,191	36,038	2,935	5,646
Net periodic benefit cost	38,194	47,137	1,145	4,760
Costs not recognized due to the effects of regulation	(6,605)	(12,986)	—	—
Net benefit cost recognized for financial reporting	$31,589	$34,151	$1,145	$4,760

	Nine Months Ended Sept. 30			
	2014	2013	2014	2013
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$66,257	$72,212	$2,592	$3,546
Interest cost	117,465	105,518	25,521	25,251
Expected return on plan assets	(155,403)	(148,839)	(25,466)	(24,759)
Amortization of transition obligation	—	—	—	618
Amortization of prior service (credit) cost	(1,310)	4,404	(8,016)	(7,314)

Amortization of net loss	87,572	108,114	8,805	16,938
Net periodic benefit cost	114,581	141,409	3,436	14,280
Costs not recognized due to the effects of regulation	(20,261)	(27,922)	—	—
Net benefit cost recognized for financial reporting	$94,320	$113,487	$3,436	$14,280

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In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2014.

13. Other Comprehensive Income

Changes in accumulated other comprehensive income (loss), net of tax, for the three and nine months ended Sept. 30, 2014 and 2013 were as follows:

	Three Months Ended Sept. 30, 2014			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at July 1	$(58,610)	$115	$(44,871)	$(103,366)
Other comprehensive (loss) income before reclassifications	(42)	2	—	(40)
Losses reclassified from net accumulated other comprehensive loss	558	—	847	1,405
Net current period other comprehensive income	516	2	847	1,365
Accumulated other comprehensive (loss) income at Sept. 30	$(58,094)	$117	$(44,024)	$(102,001)

	Three Months Ended Sept. 30, 2013			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at July 1	$(60,883)	$(135)	$(50,817)	$(111,835)
Other comprehensive income before reclassifications	22	115	—	137
Losses reclassified from net accumulated other comprehensive loss	539	—	1,179	1,718
Net current period other comprehensive income	561	115	1,179	1,855
Accumulated other comprehensive loss at Sept. 30	$(60,322)	$(20)	$(49,638)	$(109,980)

	Nine Months Ended Sept. 30, 2014			
(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive (loss) income at Jan. 1	$(59,753)	$77	$(46,599)	$(106,275)
Other comprehensive (loss) income before reclassifications	(34)	40	—	6
Losses reclassified from net accumulated other comprehensive loss	1,693	—	2,575	4,268
Net current period other comprehensive income	1,659	40	2,575	4,274
Accumulated other comprehensive (loss) income at Sept. 30	$(58,094)	$117	$(44,024)	$(102,001)

Nine Months Ended Sept. 30, 2013

(Thousands of Dollars)	Gains and Losses on Cash Flow Hedges	Unrealized Gains and Losses on Marketable Securities	Defined Benefit Pension and Postretirement Items	Total
Accumulated other comprehensive loss at Jan. 1	$(61,241)	$(99)	$(51,313)	$(112,653)
Other comprehensive (loss) income before reclassifications	(9)	79	—	70
Losses reclassified from net accumulated other comprehensive loss	928	—	1,675	2,603
Net current period other comprehensive income	919	79	1,675	2,673
Accumulated other comprehensive loss at Sept. 30	$(60,322)	$(20)	$(49,638)	$(109,980)

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Reclassifications from accumulated other comprehensive loss for the three and nine months ended Sept. 30, 2014 and 2013 were as follows:

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Three Months Ended Sept. 30, 2014		Three Months Ended Sept. 30, 2013	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$967	(a)	$829	(a)
Vehicle fuel derivatives	(16	) (b)	(24	) (b)
Total, pre-tax	951		805	
Tax benefit	(393	)	(266	)
Total, net of tax	558		539	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	1,500	(c)	1,770	(c)
Prior service (credit) cost	(86	) (c)	93	(c)
Transition obligation	—	(c)	2	(c)
Total, pre-tax	1,414		1,865	
Tax benefit	(567	)	(686	)
Total, net of tax	847		1,179	
Total amounts reclassified, net of tax	$1,405		$1,718	

(Thousands of Dollars)	Amounts Reclassified from Accumulated Other Comprehensive Loss Nine Months Ended Sept. 30, 2014		Nine Months Ended Sept. 30, 2013	
(Gains) losses on cash flow hedges:				
Interest rate derivatives	$2,869	(a)	$3,140	(a)
Vehicle fuel derivatives	(61	) (b)	(67	) (b)
Total, pre-tax	2,808		3,073	
Tax benefit	(1,115	)	(2,145	)
Total, net of tax	1,693		928	
Defined benefit pension and postretirement (gains) losses:				
Amortization of net loss	4,499	(c)	5,308	(c)
Prior service (credit) cost	(258	) (c)	279	(c)
Transition obligation	—	(c)	6	(c)
Total, pre-tax	4,241		5,593	
Tax benefit	(1,666	)	(3,918	)
Total, net of tax	2,575		1,675	
Total amounts reclassified, net of tax	$4,268		$2,603	

(a) Included in interest charges.

(b) Included in O&M expenses.

(c) Included in the computation of net periodic pension and postretirement benefit costs. See Note 12 for details regarding these benefit plans.

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, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements. Due to the seasonality of Xcel Energy's operating results, quarterly financial results are not an appropriate base from which to project annual results.

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Forward-Looking Statements

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, including the 2014 and 2015 earnings per share guidance and assumptions, are intended to be identified in this document by the words “anticipate,” “believe,” “estimate,” “expect,” “intend,” “may,” “objective,” “outl “plan,” “project,” “possible,” “potential,” “should” and similar expressions. Actual results may vary materially. Forward-lookin 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 inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; 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 Inc. 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 by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations in Item 7 of Xcel Energy Inc.’s Form 10-K for the year ended Dec. 31, 2013; 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 and Exhibit 99.01 of Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2013, and Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2014.

Financial Review

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP and is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of earnings results. We believe this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Diluted Earnings (Loss) Per Share	2014	2013	2014	2013
PSCo	$0.30	$0.33	$0.72	$0.77
NSP-Minnesota	0.27	0.31	0.63	0.67
SPS	0.13	0.11	0.23	0.19

NSP-Wisconsin	0.04	0.05	0.11	0.11
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility	0.75	0.81	1.72	1.77
Xcel Energy Inc. and other	(0.02)	(0.04)	(0.08)	(0.12)
Ongoing diluted EPS	0.73	0.77	1.64	1.65
SPS 2004 FERC complaint case orders	—	(0.04)	—	(0.04)
GAAP diluted EPS	$0.73	$0.73	$1.64	$1.61

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Earnings Adjusted for Certain Items (Ongoing Earnings)

Ongoing earnings reflect adjustments to GAAP earnings for certain items. Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

For 2013, the adjustment to GAAP earnings is related to the SPS 2004 FERC complaint case orders issued by the FERC in August 2013 for a potential SPS customer refund. As a result of the two orders, a pre-tax charge of $35 million was recorded in the third quarter of 2013. Of this amount, approximately $30 million ($26 million revenue reduction and $4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, although GAAP earnings for 2013 include the total after tax amount of $22.5 million for this charge, ongoing earnings for 2013 exclude $19.5 million of this charge. See Note 5 to the consolidated financial statements for further discussion.

Summary of Ongoing Earnings

Xcel Energy — Overall, ongoing earnings decreased $0.04 per share for the third quarter of 2014. The decrease in ongoing earnings was largely due to the impact of weather, which adversely affected earnings by $0.07 per share. Earnings results also reflect higher electric and natural gas margins due to new rates in various jurisdictions and expected lower O&M expenses, which were partially offset by higher depreciation and amortization and property taxes. Third quarter 2013 GAAP earnings included a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013 related to a 2004 complaint regarding the allocation of system average fuel costs and base rates.

PSCo — PSCo's ongoing earnings decreased $0.03 per share for the third quarter and $0.05 per share for the nine months ended Sept. 30, 2014. Increases in electric and natural gas rates, higher AFUDC, weather-normalized sales growth and lower O&M expenses were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings decreased $0.04 per share for the third quarter and nine months ended Sept. 30, 2014. Electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth were more than offset by the impact of unfavorable weather, lower AFUDC and increases in O&M expenses, property taxes and interest charges.

SPS — SPS' ongoing earnings increased $0.02 per share for the third quarter and $0.04 per share for the nine months ended Sept. 30, 2014, primarily due to higher electric rates in New Mexico and Texas and weather-normalized sales growth, partially offset by higher depreciation, O&M expenses and interest charges.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings decreased $0.01 per share for the third quarter of 2014 and were flat year-to-date. Higher electric and natural gas margins, due to an electric rate increase and weather-normalized sales growth were offset by higher O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by $0.02 per share for the third quarter and $0.04 for the nine months ended Sept. 30, 2014, largely due to lower financing costs as a result of refinancing junior subordinated notes with lower cost debt.

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Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2014 diluted EPS compared with the same period in 2013. See further discussion below.

Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30	Nine Months Ended Sept. 30
2013 GAAP diluted EPS	$0.73	$1.61
SPS 2004 FERC complaint case orders	0.04	0.04
2013 ongoing diluted EPS	0.77	1.65
Components of change — 2014 vs. 2013		
Higher electric margins	0.01	0.15
Higher natural gas margins	0.01	0.05
Lower interest charges	—	0.01
Higher AFUDC — equity	—	0.01
Lower (higher) O&M expenses	0.01	(0.06)
Higher taxes (other than income taxes)	(0.02)	(0.05)
Higher depreciation and amortization	(0.03)	(0.04)
Higher conservation and demand side management (DSM) program expenses	(0.01)	(0.04)
Dilution from equity issued through the ATM program, direct stock purchase plan and benefit plans	(0.01)	(0.02)
Other, net	—	(0.02)
2014 GAAP and ongoing diluted EPS	$0.73	$1.64

The following tables summarize the earnings contributions of Xcel Energy's business segments:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013	2014	2013
GAAP income (loss) by segment				
Regulated electric income	$360.7	$365.2	$731.8	$740.3
Regulated natural gas income	4.0	—	96.6	80.7
Other income [(a)]	15.2	17.9	35.4	35.4
Xcel Energy Inc. and other [(a)]	(11.3)	(18.3)	(38.8)	(58.2)
Total net income	$368.6	$364.8	$825.0	$798.2

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
Contributions to Diluted Earnings (Loss) Per Share	2014	2013	2014	2013
GAAP earnings (loss) by segment				
Regulated electric	$0.71	$0.73	$1.46	$1.50
Regulated natural gas	0.01	—	0.19	0.16
Other [(a)]	0.03	0.04	0.07	0.07
Xcel Energy Inc. and other [(a)]	(0.02)	(0.04)	(0.08)	(0.12)
Total diluted EPS	$0.73	$0.73	$1.64	$1.61

[(a)] Not a reportable segment. Included in all other segment results in Note 10 to the consolidated financial statements.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

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Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
HDD	(11.2)%	(46.2)%	60.9 %	11.5 %	5.4 %	4.7 %
CDD	(4.0)	15.6	(16.7)	(2.5)	25.3	(20.6)
THI	(17.3)	28.0	(32.2)	(11.2)	23.0	(24.3)

Weather — The following table summarizes the estimated impact of temperature variations on EPS compared with sales under normal weather conditions:

	Three Months Ended Sept. 30			Nine Months Ended Sept. 30		
	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013
Retail electric	$(0.024)	$0.048	$(0.072)	$0.010	$0.079	$(0.069)
Firm natural gas	—	(0.001)	0.001	0.018	0.015	0.003
Total	$(0.024)	$0.047	$(0.071)	$0.028	$0.094	$(0.066)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2014:

	Three Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(7.4)%	(10.5)%	(6.2)%	(5.2)%	(9.1)%
Electric commercial and industrial	(0.8)	2.6	0.1	(0.2)	(2.4)
Total retail electric sales	(2.7)	(1.2)	(1.4)	(1.8)	(4.5)
Firm natural gas sales	5.7	(1.6)	N/A	6.2	6.6

	Three Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	(0.4)%	(0.4)%	(2.8)%	(0.5)%	0.6 %
Electric commercial and industrial	1.5	5.1	0.8	2.5	0.6
Total retail electric sales	0.9	3.5	—	1.5	0.5
Firm natural gas sales	3.6	(4.5)	N/A	4.8	3.1

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	Nine Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(1.7)%	— %	(0.1)%	(3.1)%	(1.5)%
Electric commercial and industrial	0.8	4.4	2.4	(0.1)	(0.1)
Total retail electric sales	0.1	3.1	1.8	(1.0)	(0.6)
Firm natural gas sales	3.9	12.1	N/A	(1.1)	12.2

	Nine Months Ended Sept. 30				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.6 %	0.3 %	0.1 %	0.5 %	1.0 %
Electric commercial and industrial	1.7	4.6	2.9	1.6	0.6
Total retail electric sales	1.4	3.3	2.3	1.3	0.7
Firm natural gas sales	4.8	3.6	N/A	5.6	3.7

Weather-normalized Electric Growth (Decline)

- NSP-Wisconsin’s year-to-date electric sales growth was largely due to strong sales to large commercial and industrial (C&I) customers primarily in the oil, gas and sand mining industries.
- SPS’ year-to-date C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area. The third quarter decline of SPS residential sales was attributed to the refinement of the estimation process as a result of the recently launched SPP market and lower use per customer.
- PSCo’s year-to-date electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota’s year-to-date electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas Growth

- Across our natural gas service territories, strong sales were experienced year-to-date, which continued the trend that began in the last half of 2013. As normal weather conditions are typically defined as a 30-year average of actual weather conditions, significant weather fluctuations in periods of low demand may result in large percentage changes on small volumes. Extreme weather variations and factors such as windchill and cloud cover may not be fully reflected.

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013	2014	2013
Electric revenues	$2,616	$2,600	$7,216	$6,912
Electric fuel and purchased power	(1,080)	(1,098)	(3,188)	(3,034)
Electric margin	$1,536	$1,502	$4,028	$3,878

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The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Retail rate increases [a]	$39	$93
Fuel and purchased power cost recovery	(37)	67
Trading	12	58
Transmission revenue	6	45
Non-fuel riders	13	37
Conservation and DSM program revenues (offset by expenses)	8	33
Retail sales growth, excluding weather impact	3	22
Estimated impact of weather	(56)	(53)
Firm wholesale	7	(7)
Other, net	(5)	(17)
Total (decrease) increase in ongoing electric revenues	(10)	278
SPS 2004 FERC complaint case orders [b]	26	26
Total increase in electric revenues	$16	$304

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Retail rate increases [a]	$39	$93
Non-fuel riders	13	37
Conservation and DSM program revenues (offset by expenses)	8	33
Transmission revenue, net of costs	3	25
Retail sales growth, excluding weather impact	3	22
Estimated impact of weather	(56)	(53)
Firm wholesale	7	(7)
Other, net	(9)	(26)
Total increase in ongoing electric margin	8	124
SPS 2004 FERC complaint case orders [b]	26	26
Total increase in electric margin	$34	$150

(a) The retail rate increases include final rates in Minnesota (2013), Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota (2014), subject to and net of estimated provision for refund. See Note 5 to the consolidated financial statements for further discussion.

(b) As a result of two orders issued by the FERC, a pretax charge of approximately $35 million ($31 million in electric revenues, of which $5 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in the third quarter of 2013. See Note 5.

Natural Gas Revenues and Margin

Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013	2014	2013
Natural gas revenues	$237	$205	$1,485	$1,216
Cost of natural gas sold and transported	(99)	(75)	(934)	(703)
Natural gas margin	$138	$130	$551	$513

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The following tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Purchased natural gas adjustment clause recovery	$23	$228
Retail rate increase, net of refund (Colorado)	(1)	16
Pipeline system integrity adjustment (PSIA) rider (Colorado)	7	10
Retail sales growth	1	7
Estimated impact of weather	—	3
Other, net	2	5
Total increase in natural gas revenues	$32	$269

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Retail rate increase, net of refund (Colorado)	$(1)	$16
PSIA rider (Colorado), partially offset in O&M expenses	7	10
Retail sales growth	1	7
Estimated impact of weather	—	3
Other, net	1	2
Total increase in natural gas margin	$8	$38

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses decreased $6.9 million, or 1.2 percent, for the third quarter of 2014 and increased $47.0 million, or 2.8 percent, for the nine months ended Sept. 30, 2014. The year-to-date increase in O&M expense is partially due to the timing of a prior year nuclear outage (i.e., amortization of the Monticello outage began in July 2013).

(Millions of Dollars)	Three Months Ended Sept. 30 2014 vs. 2013	Nine Months Ended Sept. 30 2014 vs. 2013
Nuclear plant operations and amortization	$(1)	$25
Electric and natural gas distribution expenses	(1)	12
Plant generation costs	2	8
Transmission costs	1	7
Employee benefits	(9)	(18)
Other, net	1	13
Total (decrease) increase in O&M expenses	$(7)	$47

For the third quarter of 2014, O&M expenses (decreased) increased due to the following:

- Nuclear plant operations and amortization expense reductions were driven by lower plant operations spending. The expense for 2013 included one-time contractor and consulting expense for various projects and initiatives to improve the operational efficiencies of the plants.

- Electric and natural gas distribution expense declines were primarily driven by the timing of pipeline system integrity projects;
- Plant generation costs were driven by the timing of overhauls and purchases of chemicals;
- Transmission costs increased as a result of higher substation maintenance and repairs; and
- Lower employee benefits resulted primarily from decreases in pension expense, retiree medical costs and annual employee incentive accruals.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $7.4 million, or 10.9 percent, for the third quarter of 2014 and $31.3 million, or 16.3 percent, for the nine months ended Sept. 30, 2014. These increases were primarily attributable to higher electric recovery rates at NSP-Minnesota and PSCo.

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Depreciation and Amortization — Depreciation and amortization increased $26.9 million, or 11.8 percent, for the third quarter of 2014 and $35.5 million, or 4.9 percent, year-to-date. The increases were primarily attributed to normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets. See further discussion within Note 5 to the consolidated financial statements.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $12.7 million, or 12.0 percent, for the third quarter of 2014 and $38.2 million, or 11.9 percent, for the nine months ended Sept. 30, 2014. The increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC increased $2.6 million for the third quarter of 2014 and $6.9 million year-to-date. The increases were due to construction primarily related to the CACJA projects and the expansion of transmission facilities, partially offset by the reduction caused by the portion of the Monticello LCM/EPU placed in service in July 2013.

Interest Charges — Interest charges decreased $1.3 million, or 0.9 percent, for the third quarter of 2014 and $9.3 million, or 2.2 percent, for the nine months ended Sept. 30, 2014. The decreases were primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels in the current period. In addition, in 2013 interest charges were incurred for customer refunds at SPS and NSP-Minnesota and a $6.3 million write off of unamortized debt expense associated with the calling of junior subordinated notes in May 2013.

Income Taxes — Income tax expense increased $2.6 million for the third quarter of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, decreased permanent plant-related adjustments in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by a tax benefit for prior year adjustments in 2014. The ETR was 34.7 percent for the third quarter of 2014, compared to 34.6 percent for the third quarter of 2013.

Income tax expense increased $25.3 million for the first nine months of 2014. The increase in income tax expense was primarily due to higher pretax earnings in 2014, decreased permanent plant-related adjustments in 2014, recognition of research and experimentation credits in 2013 and a tax benefit for a carryback claim related to 2013. These were partially offset by the successful resolution of a 2010-2011 IRS audit issue in 2014 and a tax benefit for prior year adjustments in 2014. The ETR was 34.6 percent for the first nine months of 2014, compared to 34.0 percent for the first nine months of 2013 due to these adjustments.

Public Utility Regulation

NSP-Minnesota

NSP System Resource Plans — In March 2013, the MPUC approved NSP-Minnesota's Resource Plan and ordered a competitive acquisition process with the goal of adding approximately 500 MW of generation to the NSP System by 2019.

In May 2014, the MPUC issued its order directing NSP-Minnesota to negotiate a 100 MW solar PPA with Geronimo Energy, a natural gas, combined-cycle PPA with Calpine, and a natural gas, combustion turbine PPA with Invenergy. The MPUC also directed NSP-Minnesota to present its final pricing terms for its 215 MW natural gas combustion turbine, self-build option at the Black Dog site.

In September 2014, NSP-Minnesota filed an updated assessment of generating resource needs which indicates that it will have surplus generating capacity through at least 2019. NSP-Minnesota requested to postpone negotiations of the thermal PPAs until spring 2015. NSP-Minnesota also expressed reservations about the significant price differences in the solar options resulting from solar request for proposals (RFPs). NSP-Minnesota suggested the MPUC consolidate its determinations regarding the amount of solar to be added to the NSP System, as well as the specific mix of PPAs that will be best for NSP-Minnesota's customers.

In October 2014, NSP-Minnesota filed a petition with the MPUC seeking approval of two to three solar PPAs, depending on the MPUC's determination regarding the Geronimo Energy solar PPA. The MPUC is anticipated to act on NSP-Minnesota's recommendations in December 2014.

NSP-Minnesota's next Resource Plan is expected to be filed with the MPUC in January 2015.

CapX2020 — The estimated cost of the five major CapX2020 transmission projects listed below is $2.1 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.2 billion of the total investment. As of Sept. 30, 2014, Xcel Energy has invested $801 million of its $1.2 billion share of the five CapX2020 transmission projects.

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Hampton, Minn. to Rochester, Minn. to La Crosse, Wis. 345 kilovolt (KV) transmission line
Construction on the project started in Minnesota in January 2013 and the project is expected to go into service in 2015, although segments will be placed in service as they are completed.

Monticello, Minn. to Fargo, N.D. 345 KV transmission line
In December 2011, the Monticello, Minn. to St. Cloud, Minn. portion of the Monticello, Minn. to Fargo, N.D. project was placed in service. In April 2014, the St. Cloud, Minn. to Alexandria, Minn. portion of the project was placed in service. In January 2013, construction started on the project in North Dakota. The final phase of the project, Alexandria, Minn. to Fargo, N.D. is expected to go into service in 2015.

Brookings County, S.D. to Hampton, Minn. 345 KV transmission line
In December 2011, MISO granted the final approval of the project as a multi-value project (MVP). Construction started on the project in Minnesota in May 2012. The project is expected to go fully into service in 2015, although segments will be placed in service as they are completed.

Bemidji, Minn. to Grand Rapids, Minn. 230 KV transmission line
The Bemidji, Minn. to Grand Rapids, Minn. line was placed in service in September 2012.

Big Stone South to Brookings County, S.D. 345 KV transmission line
In December 2011, MISO granted final approval of the project as a MVP. In March 2014, the SDPUC approved a permit for construction of the project’s southern portion. Construction is anticipated to begin in late 2015, with completion in 2017.

Minnesota Solar — Minnesota legislation requires 1.5 percent of a public utility’s total electric retail sales to retail customers be generated using solar energy by 2020. Of the 1.5 percent, 10 percent must come from systems sized less than 20 kilowatts. There are two solar programs authorized by the legislature: a community solar garden program that will provide bill credits to participating subscribers and a production incentive program for solar energy systems equal to or less than 20 kilowatts with authorized payments of $5.0 million per year over five years. The legislation also provides for an alternative tariff based on a distributed solar value or Value of Solar (VOS) methodology.

In March 2014, a VOS methodology was approved by the MPUC. However, in September 2014 the MPUC determined that the VOS is not in the public interest for use with community solar gardens. The MPUC instead approved a retail rate based credit ranging from 9.5 to 15 cents per kilowatt hour. The actual bill credit amount is dependent on customer class as well as customers’ willingness to transfer the REC to NSP-Minnesota.

Minneapolis, Minn. Franchise Agreement — In October 2014, the City of Minneapolis and Xcel Energy signed a 10 year franchise agreement. The City of Minneapolis has the option to end the agreement any time after the first five years, provided that a 12 month notice is given to Xcel Energy, and the option to extend it to a maximum of 20 years if both parties agree. A separate clean energy partnership agreement with the City of Minneapolis was also signed, which establishes a board comprised of city and utility officials tasked with creating a work plan shaped by the city’s Climate Action Plan by promoting energy efficiency, the use of renewable energy, and the reduction of carbon emissions.

Nuclear Power Operations

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the PI plant. See Note 14 of Xcel Energy Inc.’s Annual Report on Form 10-K for the year ended Dec. 31, 2013 for further discussion regarding the nuclear generating plants.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 has resulted in additional regulation regarding plant readiness to safely manage severe events, which is expected to require additional capital expenditures and operating expenses.

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In March 2012, the NRC issued three orders which included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The NRC also requested additional information including requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards and to assess the emergency preparedness staffing and communications capabilities at each plant. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance to meet the orders is expected to begin in the second quarter of 2015 with all units expected to be fully compliant by December 2016.

In June 2013, the NRC issued a revised order with regard to reliable hardened containment vents. The revised order added severe accident conditions under which the existing hardened vent which comes off of the wet portion of the containment needs to operate and requires a second hardened vent off of the dry portion of the containment. The revised order requires that any necessary changes to the existing vent are to be completed by the second quarter of the 2017 refueling outage at the Monticello plant and a new vent to be added by the second quarter of the 2019 refueling outage. Portions of the work that fall under the requests for additional information are expected to be completed by 2018.

NSP-Minnesota expects that complying with these external event requirements will cost approximately $80 to $100 million at the Monticello and PI plants. The majority of these costs are expected to be capital in nature and are included in NSP-Minnesota’s capital expenditure forecasts. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

The NRC continues to review its requirements for mitigating the risks of external events on nuclear plants. In April 2014, the NRC issued a draft of proposed regulatory guidance for risk mitigation of tornado missiles (projectiles impacting the plant). This draft guidance is subject to public comments, further NRC review and possibly public meetings prior to finalization. NSP-Minnesota expects the costs associated with compliance with new NRC regulatory guidance for missile protection to be capital in nature and recoverable from customers. However, at this time NSP-Minnesota is still evaluating the proposed new requirements and has not yet estimated their financial impact.

NSP-Wisconsin

NSP-Wisconsin CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the Hampton, Minn. to La Crosse, Wis. project in May 2012. The Wisconsin route is approximately 50 miles of new transmission line with an estimated cost of $211 million. Construction on the Wisconsin terminus of the line, the Briggs Road Substation, began in mid-2013 and construction on the Wisconsin portion of the line began in June 2014. The line is expected to go into service in 2015.

NSP-Wisconsin / American Transmission Company, LLC (ATC) - La Crosse, Wis. to Madison, Wis. Transmission Line — In October 2013, NSP-Wisconsin and ATC jointly filed an application with the PSCW for a CPCN for a new 345 KV transmission line that would extend from La Crosse, Wis. to Madison, Wis. The proposed line, known as the Badger Coulee line, would run between 159 and 182 miles based on the permitted route. Updated information was provided to the PSCW in April 2014 showing an estimated project cost, including AFUDC, of between $540 and $580 million, depending upon the route ultimately approved by the PSCW. NSP-Wisconsin’s share of the investment is estimated to be between $190 and $207 million. In December 2011, MISO determined the line to be a MVP project, and as such, eligible for cost sharing under MISO’s MVP tariff. The project is currently pending before the PSCW, with a decision expected in April 2015. If approved, NSP-Wisconsin and ATC anticipate beginning construction on the line in mid-2016, with completion by late-2018.

PSCo

Brush, Colo. to Castle Pines, Colo. 345 KV Transmission Line — In March 2014, PSCo filed with the CPUC for a CPCN to construct a new 345 KV transmission line originating from Pawnee Station, near Brush, Colo. and terminating at the Daniels Park substation, near Castle Pines, Colo. The estimated cost of the project is $178 million. In September 2014, PSCo entered into a partial settlement agreement with the CPUC Staff that would grant a CPCN for the line. The Office of Consumer Counsel (OCC) has opposed the CPCN. A CPUC decision is expected by early 2015.

Renewable Energy Standard (RES) Compliance Plan — Colorado law mandates that at least 30 percent of PSCo’s energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. In July 2013, PSCo filed its 2014 RES compliance plan that included the continuation of both the Solar*Rewards and Solar*Rewards Community programs. On July 31, 2014, the ALJ issued a recommended decision accepting PSCo’s compliance plan with modifications. PSCo and several parties have filed exceptions to this recommended decision. A CPUC decision is anticipated in the fourth quarter of 2014.

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Net Metering Standard — In conjunction with its 2014 RES compliance plan filing, PSCo proposed to track and quantify the system costs that are not avoided by distributed solar generation, which PSCo has defined as a "net metering incentive," for purposes of equitably recovering costs between customers who participate in distributed generation and customers that do not. The CPUC has assigned the net metering issue to its own docket and established key dates to evaluate this matter. A CPUC decision is anticipated in the fourth quarter of 2014.

Solar*Connect Program — In April 2014, PSCo filed an application with the CPUC seeking approval for a program that would allow customers the option to purchase a portion or all of their electricity from a utility scale solar facility approximately 50 MW in size. Customer contracts under the program would run a minimum of one year. Several parties have opposed or offered modifications to the program. Hearings have been set for November 2014. A CPUC decision is anticipated in the fourth quarter of 2014.

Boulder, Colo. Municipalization — PSCo's franchise agreement with the City of Boulder (Boulder) expired on Dec. 31, 2010. In November 2011, a ballot measure was passed by the citizens of Boulder, which authorized the formation and operation of a municipal light and power utility and the issuance of enterprise revenue bonds, subject to certain restrictions, including the level of initial rates and debt service coverage.

In May 2014, the Boulder City Council passed an ordinance to establish an electric utility. In June 2014, PSCo filed a complaint in the Boulder District Court seeking a declaratory ruling that this ordinance violates Boulder's charter requirements. Subsequently, Boulder filed a motion to dismiss PSCo's complaint, which is still pending.

The CPUC has previously ruled that it has jurisdiction under Colorado law to determine the utility that will serve customers outside Boulder's city limits, and will determine certain system separation matters as well as what facilities need to be constructed to ensure reliable service. The CPUC has declared that it should make its determinations prior to any eminent domain actions. In January 2014, Boulder appealed this ruling to the Boulder District Court. PSCo and the CPUC filed briefs in June 2014 in opposition of Boulder's appeal. This matter is currently pending.

Boulder sent PSCo an offer of $128 million for certain portions of PSCo's transmission and distribution business, which includes Boulder and certain areas outside city limits. PSCo has notified Boulder that its offer has deficiencies related to property descriptions as well as other relevant information impacting the remainder of PSCo's system. Under Colorado law, a condemning entity must pay the owner fair market value for the taking of and damages to the remainder of the property. In July 2014, Boulder filed a petition for condemnation in the Boulder District Court. PSCo filed a motion to dismiss the petition based upon the CPUC's ruling that it must determine the appropriate system separations prior to Boulder filing its condemnation case. PSCo's motion to dismiss is currently pending.

In August 2014, PSCo filed a petition with the FERC requesting an order requiring that Boulder's attempt to acquire PSCo's transmission and distribution facilities by condemnation requires prior FERC approval under the Federal Power Act. Boulder and The American Public Power Association opposed the petition in October 2014. This matter is currently pending FERC action.

If Boulder is allowed to proceed with its condemnation petition and were to succeed in the eminent domain proceeding, PSCo would seek to obtain full compensation for the business and its associated property taken by Boulder, as well as for all damages resulting to PSCo and its system. PSCo would also seek appropriate compensation for stranded costs with the FERC.

SPS

SPP Integrated Market (IM) — In 2012 and 2013, the FERC approved proposed revisions to the SPP tariff to allow SPP to operate a day ahead and real time energy and ancillary services market. The SPP IM began operations on March 1,

2014. SPS submitted filings to the FERC to modify its wholesale power sales contracts to allow recovery of SPP IM charges and revenues through the SPP wholesale fuel clause adjustment (FCA). The FERC approved the FCA tariff filings in April 2014. SPS also requested approval to make sales to the SPP IM at market-based rates, which the FERC approved in February 2014. SPS has also filed changes to its QF tariffs in Texas and New Mexico to revise the pricing applied to QF purchases to be consistent with the new market. In February 2014, SPS was granted interim approval of the revised QF tariff in Texas to coincide with the start of the IM. The New Mexico revised QF tariff was approved in March 2014.

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SPS Transmission Notifications to Construct (NTCs) — In April 2014, the SPP Board of Directors approved the High Priority Incremental Load Study Report, a reliability assessment that evaluated the anticipated transmission needs of certain parts of the SPP resulting from expected load growth in the area. As a result of this study, SPS has received NTCs and conditional NTCs for 44 new transmission projects to be placed into service by 2020. SPS is in the process of evaluating these projects and their costs internally before submitting certificates of convenience and necessity (CCNs) to the PUCT and the NMPRC. These projects are intended to provide regional reliability benefits as well as the ability to serve the increase in load in Southeastern New Mexico.

TUCO substation to Woodward, Okla. 345 KV transmission line
The TUCO to Woodward District extra high voltage interchange is a 345 KV transmission line. SPS constructed the line to just inside the Oklahoma state line, and Oklahoma Gas and Electric Company (OGE) built from there to Woodward, Okla. SPS' investment in the TUCO to Woodward line and substation is approximately $205 million and is expected to be recovered from SPP members, including SPS, in accordance with the SPP open access transmission tariff (OATT) and the ratemaking process. The line was placed into service in September 2014.

Hitchland substation to Woodward, Okla. 345 KV transmission line
The Hitchland substation to Woodward, Okla. line is a 345 KV double circuit transmission line and associated substation facilities in the Oklahoma and Texas Panhandle. SPS built the first 30 miles and OGE completed the line from there to Woodward, Okla. SPS' investment for the Hitchland to Woodward line and substation is approximately $59 million and is expected to be recovered from SPP members in accordance with the SPP OATT and the ratemaking process. The line was placed into service in May 2014.

Potash Junction substation to Roadrunner substation 345 KV transmission line
In April 2014, SPS filed a CCN with the NMPRC for a new 345 KV transmission line from the Potash Junction substation to the Roadrunner substation, both near Carlsbad, N.M. The proposed line would run 40 miles and cost an estimated $54 million. Approval for the CCN is pending. A hearing has been scheduled for November 2014.

Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries, including enforcement of North American Electric Reliability Corporation (NERC) mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' 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 Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2013. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order, New ROE Policy — In June 2014, the FERC adopted a new two-step ROE methodology for electric utilities. In October 2014, the FERC upheld the determination of the long term growth rate to be used in its new ROE methodology. Several parties sought rehearing of the June 2014 order and therefore the new FERC policy may be subject to additional changes.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In 2011, the FERC issued a final ruling, Order 1000, adopting new requirements for transmission planning, cost allocation and development to be effective prospectively. In Order 1000, the FERC required utilities to develop tariffs that provide for joint regional transmission planning and cost allocation for all FERC-jurisdictional utilities within a region. In addition, Order 1000 required that regions coordinate to develop interregional plans for transmission planning and cost allocation. A key provision of Order 1000 is a requirement that FERC-jurisdictional wholesale transmission tariffs exclude provisions that would grant the incumbent transmission owner a federal Right of First Refusal (ROFR) to build certain types of transmission projects in its service area. Various parties, including the MISO Transmission Owners, filed appeals of Order 1000 with the D.C. Circuit. In August 2014, the Court denied all appeals and upheld Order 1000 in its entirety. The Court indicated, however, that challenges to removal of federal ROFR provisions from individual contracts or tariffs could be considered in individual compliance filings.

The removal of a federal ROFR would eliminate rights that NSP-Minnesota, NSP-Wisconsin and SPS currently have under the MISO and SPP tariffs to build certain transmission projects within their footprints. In Order 1000, FERC instead required that the opportunity to build such projects would extend to competitive transmission developers. MISO, SPP, and PSCo all made their initial compliance filings to incorporate new provisions into their tariffs regarding regional planning and cost allocation. Subsequently, the FERC ruled on the initial regional compliance filings, directing further compliance changes. The MISO, SPP and PSCo regional compliance filings all remain pending further action by the FERC.

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Initial filings to address Order 1000 interregional planning and cost allocation requirements with other regions were also made by MISO, SPP and PSCo and are pending initial action by the FERC.

NSP System
Minnesota, North Dakota and South Dakota legislation preserves ROFR rights; however, Wisconsin does not have legislation protecting ROFR rights for incumbent utilities.

Regional planning and cost allocation
The FERC's initial order on MISO's compliance filing required MISO to remove pre-existing federal ROFR provisions in the MISO Transmission Owners Agreement (TOA) and tariff, and rejected proposed tariff provisions that would have recognized state ROFR rights and allowed state regulators to select the developer of a transmission project. Xcel Energy and other parties requested rehearing of this issue. In May 2014, FERC denied rehearing on the issue of whether ROFR provisions must be removed from the MISO TOA and MISO tariff, but ruled that MISO can consider state statutes when determining whether to approve an applicant for a competitive project. The MISO transmission owners filed an appeal of the FERC orders with the U.S. Court of Appeals for the Seventh Circuit; action on the appeal is pending. The FERC also accepted changes to MISO's transmission cost allocation procedures that will protect the ROFR for projects needed for system reliability. MISO submitted a compliance filing to the May 2014 order on July 14, 2014, which is pending FERC action. MISO has proposed that the Order 1000 compliance tariffs be effective for projects approved in December 2014.

Interregional planning and cost allocation
MISO submitted its initial Order 1000 interregional compliance filing in July 2013. The filing is pending initial action by the FERC.

PSCo
The State of Colorado does not have legislation protecting ROFR rights for incumbent utilities.

Regional planning and cost allocation
PSCo submitted its FERC regional compliance filing in October 2012 proposing that it would join the WestConnect region, a consortium of FERC jurisdictional utilities in the Western Interconnection. In September 2013, PSCo and other WestConnect utilities submitted their updated regional compliance filings. In September 2014, the FERC issued an order partially accepting and partially rejecting the September 2013 compliance filings. FERC ordered additional compliance filings within 60 days. PSCo and other WestConnect utilities requested rehearing of the September 2014 FERC order and plan to submit additional compliance filings in November 2014.

Interregional planning and cost allocation
PSCo and other WestConnect members' interregional compliance filings were submitted in May 2013 and are pending initial FERC action.

The WestConnect members proposed that the Order 1000 regional and interregional compliance tariffs be effective prospectively after the final FERC orders, and not earlier than Jan. 1, 2015.

SPS
Xcel Energy believes that Texas statutes protect the ROFR of incumbent utilities operating outside of the ERCOT region to construct and own transmission interconnected to their systems, though this view is disputed by some parties. The State of New Mexico does not have legislation establishing ROFR rights for incumbent utilities.

Regional planning and cost allocation

The FERC issued its initial order on SPP’s Order 1000 regional compliance filing in July 2013. The FERC identified several areas that required a further compliance filing by SPP to address regional compliance issues. Among other things, the FERC rejected SPP’s proposal to retain a ROFR for new transmission projects with operational voltages between 100 KV and 300 KV. Requests for rehearing of the FERC’s July 2013 order were filed in August 2013 and are pending the FERC’s action. The SPP regional compliance filing was filed in November 2013 and is currently pending FERC action. The SPP regional compliance tariffs went into effect March 1, 2014, subject to the outcome of the additional FERC proceedings.

Interregional planning and cost allocation
The SPP interregional compliance filing was submitted in July 2013 and is pending initial FERC action.

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Transmission-only Subsidiaries (TransCos) — In 2014, Xcel Energy formed the Xcel Energy Transmission Holding Company, LLC and two second-tier transmission subsidiaries that will participate in the MISO and SPP competitive bidding processes as a qualified transmission developer (QTD) and qualified RFP participant (QRP), respectively. Transmission assets held by these entities will be subject to FERC jurisdiction.

Xcel Energy Transmission Development Company, LLC (XETD) was approved as a non-transmission owning member in MISO in April 2014, and a QTD in September 2014. This allows XETD to competitively bid for MISO transmission projects starting in 2015 or 2016.

Xcel Energy Southwest Transmission Company, LLC (XEST) filed a QRP application in June 2014, which SPP found complete in September 2014. This allows XEST to competitively bid for SPP transmission projects starting in 2015.

In August 2014, XETD and XEST filed forward-looking transmission formula rates with the FERC that will apply in their respective jurisdictions with a requested effective date of Nov. 1, 2014. The TransCo rate filings are pending action by the FERC, which is expected by the end of 2014.

- Both TransCos requested a capital structure based on 55 percent equity and 45 percent debt.
- XETD requested a base ROE using the currently applicable MISO regional rate of 12.38 percent, subject to any potential modifications resulting from a pending ROE complaint against MISO and the MISO transmission owners.
- XEST requested a base ROE of 10.64 percent, plus a 50 basis point adder for membership in SPP. Certain parties protested or commented on the formula rate filings, and XEST and XETD filed answers on Oct. 6, 2014.

NERC Critical Infrastructure Protection (CIP) Requirements — The FERC has approved version 5 of NERC's CIP standards. Requirements must be applied to high and medium impact assets by April 1, 2016 and to low impact assets by April 1, 2017. Xcel Energy is currently in the process of evaluating the new requirements and identifying initiatives needed to meet the compliance deadlines.

NERC Physical Security Requirements — In July 2014, the FERC issued a notice of proposed rulemaking generally proposing to adopt NERC's proposed CIP standard related to physical security for bulk electric system facilities. However, the FERC proposed a modification to the standard that would allow certain governmental authorities, including FERC, to revise an entity's list of critical facilities. Xcel Energy expects prompt action by FERC to finalize the rule with a likely effective date in 2015. Xcel Energy is currently in the process of evaluating and identifying the critical facilities impacted to better determine the cost of protections necessary to meet the standard. The additional cost for compliance is anticipated to be recoverable through rates.

SPP and MISO Complaints Regarding RTO Joint Operating Agreement (JOA) — SPP and MISO have a longstanding dispute regarding the interpretation of their JOA, which is intended to coordinate RTO operations along the MISO/SPP system boundary. SPP and MISO disagree over MISO's authority to transmit power over SPP transmission facilities between the traditional MISO region in the Midwest and the Entergy system. Several cases have been filed with the FERC by MISO and SPP. In March 2014, FERC issued an order setting all of the cases for settlement judge proceedings, or hearings if settlement fails. If SPP is successful in charging MISO for use of the SPP system, the NSP System would experience higher costs from MISO, which could be material, but SPS would collect revenues from SPP. The outcome of the JOA disputes, and the potential impact on Xcel Energy, are uncertain at this time. In June 2014, the FERC accepted a proposed tariff change by MISO to recover transmission charges imposed by SPP retroactive to Jan. 29, 2014, and set the issues for settlement judge and hearing procedures which are still underway.

Environmental, Legal and Other Matters

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

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Critical Accounting Policies and Estimates

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported even if the nature of the accounting policies applied have not changed. Item 7 — Management's Discussion and Analysis, in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013, includes a discussion of accounting policies and estimates 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. As of Sept. 30, 2014, there have been no material changes to policies set forth in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2013.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss that may occur as a result of adverse 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. See Note 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy Inc.'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.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and 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.

At Sept. 30, 2014, the fair values by source for net commodity trading contract assets were as follows:

	Futures / Forwards					
(Thousands of Dollars)	Source of Fair Value	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	(a)	$9,153	$9,540	$1,076	$(413)	$19,356
NSP-Minnesota	(b)	4,605	—	—	—	4,605
		$13,758	$9,540	$1,076	$(413)	$23,961

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Options

(Thousands of Dollars)	Source of Fair Value	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	(b)	$4	$—	$—	$—	$4

(a) — Prices actively quoted or based on actively quoted prices.
(b) — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Nine Months Ended Sept. 30	
(Thousands of Dollars)	2014	2013
Fair value of commodity trading net contract assets outstanding at Jan. 1	$30,514	$28,314
Contracts realized or settled during the period	(9,225)	(6,018)
Commodity trading contract additions and changes during period	2,676	9,392
Fair value of commodity trading net contract assets outstanding at Sept. 30	$23,965	$31,688

At Sept. 30, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $1.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $1.4 million. At Sept. 30, 2013, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.4 million.

Xcel Energy Inc.'s utility subsidiaries' 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, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Three Months Ended Sept. 30	VaR Limit	Average	High	Low
2014	$0.60	$3.00	$0.50	$4.06	$0.13
2013	0.48	3.00	0.45	1.35	0.18

Nuclear Fuel Supply — In December 2014, NSP-Minnesota is scheduled to take delivery of 69 percent of its 2014 enriched nuclear material requirements and in December 2015 approximately 13 percent of its 2015 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. NSP-Minnesota has arranged for deliveries of material from alternate sources in 2014 and 2015 that would not be impacted by these world events and provide the flexibility to manage its nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near term. Long term through 2024, NSP-Minnesota is scheduled to take delivery of approximately 34 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure security of supply of enriched nuclear material beyond 2015.

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

At Sept. 30, 2014 and 2013, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense annually by approximately $7.1 million and $4.4 million, respectively. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

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NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Sept. 30, 2014, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have an impact on earnings.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Sept. 30, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $35.2 million, while a decrease in prices of 10 percent would have resulted in a decrease in credit exposure of $14.1 million. At Sept. 30, 2013, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $37.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $12.7 million.

Xcel Energy Inc. 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. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 8 to the consolidated financial statements for further discussion of the fair value hierarchy and 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 not material to the fair value of commodity derivative assets at Sept. 30, 2014. 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 risk was immaterial to the fair value of commodity derivative liabilities at Sept. 30, 2014.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 5.0 percent and 57.7 percent of total assets and liabilities, respectively, measured at fair value at Sept. 30, 2014.

Determining the fair value of FTRs 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 included $91.0 million and $17.3 million of estimated fair values, respectively, for FTRs held at Sept. 30, 2014.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility 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 derivative assets included no assets and no liabilities, for forwards held at Sept. 30, 2014. There were no Level 3 options held at Sept. 30, 2014.

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Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $161.0 million in the nuclear decommissioning fund at Sept. 30, 2014 (approximately 8.8 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013
Cash provided by operating activities	$2,004	$2,003

Net cash provided by operating activities increased $1 million for the nine months ended Sept. 30, 2014, compared with the nine months ended Sept. 30, 2013. The increase was primarily due to changes in regulatory assets and liabilities, lower pension contributions and higher net income, partially offset by changes in working capital related to the timing of payments and receipts.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013
Cash used in investing activities	$(2,235)	$(2,311)

Net cash used in investing activities decreased $76 million for the nine months ended Sept. 30, 2014, compared with the nine months ended Sept. 30, 2013. The decrease was primarily attributable to higher capital expenditures in 2013 associated with several major construction projects including the Monticello nuclear EPU and the PI steam generator replacement. The change in capital expenditures was partially offset by the impact of higher 2013 insurance proceeds related to Sherco Unit 3.

	Nine Months Ended Sept. 30	
(Millions of Dollars)	2014	2013
Cash provided by financing activities	$261	$327

Net cash provided by financing activities decreased $66 million for the nine months ended Sept. 30, 2014, compared with the nine months ended Sept. 30, 2013. The decrease was primarily due to lower proceeds from long-term debt, less issuances of common stock and higher dividend payments, partially offset by lower repayments of short-term and long-term debt.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Capital Expenditures — The current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2014 through 2019 are shown in the table below.

	Forecast						
(Millions of Dollars)	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
By Subsidiary							
NSP-Minnesota	$1,130	$1,625	$990	$975	$845	$950	$5,385

PSCo	1,055	950	820	815	885	1,010	4,480
SPS	535	570	710	735	595	565	3,175
NSP-Wisconsin	280	230	260	300	325	325	1,440
Total capital expenditures	$3,000	$3,375	$2,780	$2,825	$2,650	$2,850	$14,480

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	Forecast						
(Millions of Dollars)	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
By Function							
Electric transmission	$985	$875	$780	$905	$975	$1,000	$4,535
Electric generation	715	1,190	630	620	415	450	3,305
Electric distribution	560	605	630	640	650	680	3,205
Natural gas	380	370	370	305	355	380	1,780
Nuclear fuel	130	90	120	120	65	150	545
Other	230	245	250	235	190	190	1,110
Total capital expenditures	$3,000	$3,375	$2,780	$2,825	$2,650	$2,850	$14,480

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, renewable portfolio standards and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy's TransCos.

Financing — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. The current estimated financing plans of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2019 are shown in the table below.

(Millions of Dollars)	
Funding Capital Expenditures	
Cash from Operations*	$11,500
New Debt**	2,605
Equity from Dividend Reinvestment Program (DRIP) and Benefit Programs	375
2015-2019 Capital Expenditures	$14,480
Maturing Debt	$2,995

*Cash from operations, net of dividend and pension funding.
**Reflects a combination of short and long-term debt.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and the SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation, there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. An entity may deal in utility operations-related swaps and not be required to register as a swap dealer provided that the aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that the entity has not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy has completed its review of the additional reporting obligations for "trade options," which are physical electric and gas contracts that contain embedded volumetric and/or price optionality. At this time, none of the contracts used by Xcel Energy qualify as a "trade option." However, this determination is subject to change as additional Dodd-Frank Act rules continue to be finalized and implemented and subsequent transactions are executed. Xcel Energy is currently meeting all other reporting requirements.

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SPP FTR Margining Requirements — The SPP conducted its first annual FTR auction in the spring of 2014 associated with the implementation of the SPP IM. The full process for transmission owners involves the receipt of Auction Revenue Rights (ARRs) and, if elected by the transmission owner, conversion of those ARRs to firm FTRs. At Sept. 30, 2014, SPS had a $41 million letter of credit posted with SPP. That collateral initially supported the ARR to FTR conversion activity for the first summer of IM operation. In October 2014, the letter of credit was reduced to $30 million.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income securities, and alternative investments, including private equity, real estate, hedge fund of funds and commodity investments.

- In January 2014, contributions of $130.0 million were made across three of Xcel Energy's pension plans;
- In 2013, contributions of $192.4 million were made across four of Xcel Energy's pension plans; and
- For future years, we anticipate contributions will be made as necessary.

Actuarial Assumptions — In October 2014, the Society of Actuaries published the final RP-2014 (base mortality tables) and MP-2014 (improvement projection scale). These reports are used, in part, to establish life expectancy assumptions in the United States for purposes of estimating pension and postretirement health care benefit obligations, costs and required contributions. Xcel Energy is currently evaluating the impact of the new tables, as well as potential alternative assumptions on the Dec. 31, 2014 valuations and future expected contributions. For purposes of determining ERISA funding calculations for qualified pension plans, the IRS has indicated that the revised tables would not be required until the 2016 valuation year.

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Sept. 30, 2014, approximately $3.2 million of cash was held in these accounts.

Amended Credit Agreements — On Oct. 14, 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an extension of maturity from July 2017 to October 2019. In addition, the borrowing limit for Xcel Energy Inc. has been increased to $1 billion from $800 million and the borrowing limit for SPS has been increased to $400 million from $300 million. As a result, the total borrowing limit under the amended credit agreements increased to $2.75 billion from $2.45 billion.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

Credit Facilities — As of Oct. 27, 2014, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity

Xcel Energy Inc.	$1,000.0	$360.0	$640.0	$0.3	$640.3
PSCo	700.0	334.5	365.5	0.8	366.3
NSP-Minnesota	500.0	114.9	385.1	1.1	386.2
SPS	400.0	66.0	334.0	0.4	334.4
NSP-Wisconsin	150.0	32.0	118.0	0.9	118.9
Total	$2,750.0	$907.4	$1,842.6	$3.5	$1,846.1

(a) These credit facilities have been amended to expire in October 2019.

(b) Includes outstanding commercial paper and letters of credit.

Commercial Paper — As of Oct. 14, 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $1 billion for Xcel Energy Inc.;

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- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Sept. 30, 2014	Twelve Months Ended Dec. 31, 2013
Borrowing limit	$2,450	$2,450
Amount outstanding at period end	697	759
Average amount outstanding	730	481
Maximum amount outstanding	894	1,160
Weighted average interest rate, computed on a daily basis	0.33 %	0.31 %
Weighted average interest rate at period end	0.33	0.25

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

2014 Financing Activity — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund capital programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes.

During 2014, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In March, PSCo issued $300 million of 4.30 percent first mortgage bonds due March 15, 2044;
- In May, NSP-Minnesota issued $300 million of 4.125 percent first mortgage bonds due May 15, 2044;
- In June, SPS issued $150 million of 3.30 percent first mortgage bonds due June 15, 2024; and
- In June, NSP-Wisconsin issued $100 million of 3.30 percent first mortgage bonds due June 15, 2024.

Xcel Energy Inc. issued approximately 5.7 million shares of common stock through an ATM program for approximately $175 million during the first six months of 2014. As a result, Xcel Energy completed its ATM program as of June 30, 2014. Xcel Energy does not anticipate issuing any additional equity, beyond its DRIP and benefit programs, over the next five years based on its current capital expenditure plan.

Financing Plans — During 2015, Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following:

- Xcel Energy Inc. plans to issue approximately $500 million of senior unsecured bonds;
- PSCo plans to issue approximately $400 million of first mortgage bonds;
- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds;
- SPS plans to issue approximately $250 million of first mortgage bonds; and
- NSP-Wisconsin plans to issue approximately $100 million of first mortgage bonds.

Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

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Earnings Guidance

Xcel Energy anticipates that 2014 ongoing earnings will be within the guidance range of $1.95 to $2.05 per share. This is compared with the previously stated guidance range of $1.90 to $2.05 per share. Key assumptions related to 2014 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to increase approximately 3.0 percent.
- Capital rider revenue is projected to increase by $40 million to $50 million over 2013 levels.
- O&M expenses are projected to increase approximately 2 percent to 3 percent over 2013 levels.
- Depreciation expense is projected to increase $30 million to $40 million over 2013 levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota’s moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $81 million in 2014.
- Property taxes are projected to increase approximately $40 million to $50 million over 2013 levels.
- Interest expense (net of AFUDC — debt) is projected to decrease $5 million to $15 million from 2013 levels.
- AFUDC — equity is projected to increase up to $10 million over 2013 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 504 million shares.

Xcel Energy’s 2015 ongoing guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2.0 percent.
- Capital rider revenue is projected to increase by $65 million to $75 million over 2014 projected levels.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 projected levels.
- Depreciation expense is projected to increase $160 million to $180 million over 2014 projected levels, reflecting the proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota’s moderation plan in the Minnesota electric rate case. The moderation plan, if approved by the MPUC, would reduce depreciation expense by approximately $30 million in 2015.
- Property taxes are projected to increase approximately $75 million to $85 million over 2014 projected levels. The increase reflects that incremental property taxes in Colorado are no longer being deferred and also the amortization of previously deferred property taxes.
- Interest expense (net of AFUDC — debt) is projected to increase $65 million to $75 million over 2014 projected levels.
- AFUDC — equity is projected to decline approximately $30 million to $40 million from 2014 projected levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

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- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on a normalized 2013 EPS of $1.90 per share, which represented the mid-point of our 2013 earnings guidance range;
- Deliver annual dividend increases of 4 percent to 6 percent; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis — Derivatives, Risk Management and Market Risk under Item 2.

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Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of Sept. 30, 2014, 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 its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were 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

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Note 5 to the consolidated financial statements for discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2013, which is incorporated herein by reference. There have been no material changes from the risk factors previously disclosed in the Form 10-K.

Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the quarter ended Sept. 30, 2014:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
July 1, 2014 — July 31, 2014	—	$—	—	—
Aug. 1, 2014 — Aug. 31, 2014	—	—	—	—
Sept. 1, 2014 — Sept. 30, 2014	—	—	—	—
Total	—		—	—

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Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
10.01*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among Xcel Energy Inc., as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.01 to Form 8-K, dated Oct. 14, 2014 (file no. 001-03034)).
10.02*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Minnesota, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.02 to Form 8-K, dated Oct. 14, 2014 (file no. 000-31387)).
10.03*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among PSCo, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.03 to Form 8-K, dated Oct. 14, 2014 (file no. 001-03280)).
10.04*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among SPS, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.04 to Form 8-K, dated Oct. 14, 2014 (file no. 001-03789)).
10.05*	Amended and Restated Credit Agreement, dated as of Oct. 14, 2014 among NSP-Wisconsin, as Borrower, the several lenders from time to time parties thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., and Barclays Bank Plc, as Syndication Agents, and Wells Fargo Bank, National Association, as Documentation Agent (Incorporated by reference to Exhibit 99.05 to Form 8-K, dated Oct. 14, 2014 (file no. 001-03140)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	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.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended Sept. 30, 2014 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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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.
Oct. 31, 2014	By:	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage Vice President and Controller (Principal Accounting Officer)
		/s/ TERESA S. MADDEN Teresa S. Madden Senior Vice President and Chief Financial Officer (Principal Financial Officer)