TUCSON ELECTRIC POWER CO
Form 10-Q
November 07, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended September 30, 2014
OR

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

For the transition period from to .
Commission File Number 1-5924
TUCSON ELECTRIC POWER COMPANY (Exact name of registrant as specified in its charter)

Arizona (State or other jurisdiction of incorporation or organization)	86-0062700 (I.R.S. Employer Identification No.)

88 East Broadway Boulevard, Tucson, AZ 85701
(Address of principal executive offices)(Zip Code)
Registrant's telephone number, including area code: (520) 571-4000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer ¨ Accelerated Filer ¨ Non-accelerated Filer x 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 ¨ No x
As of October 20, 2014, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation.

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DEFINITIONS

The abbreviations and acronyms used in the third quarter 2014 Form 10-Q are defined below:

2010 TEP Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Covenants Agreement	A Lender Rate Mode Covenants Agreement between TEP and the purchaser of $100 million of unsecured tax-exempt bonds that were issued on behalf of TEP in November 2013 and sold in a private placement
2013 TEP Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base O&M	A non-GAAP financial measure that represents the fundamental level of operating and maintenance expense related to our business
Base Rates	The portion of TEP's Retail Rates attributed to generation, transmission, distribution and customer costs. Base Rates exclude authorized charges designed to recover specific costs that are passed through to customers including fuel and purchased energy costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Btu	British thermal unit(s)
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DG	Distributed Generation
DSM	Demand Side Management
ECA	Environmental Compliance Adjustor
EE	Energy Efficiency
Entegra	A subsidiary of Entegra Power Group LLC
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada
Four Corners	Four Corners Generating Station
GBtu	Billion British thermal units
GWh	Gigawatt-hour(s)
Gila River Unit 3	Unit 3 of the Gila River Generating Station
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kV	Kilo-volt
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter of Credit
Merger	The acquisition of UNS Energy in 2014 pursuant to the Agreement and Plan of Merger between UNS Energy Corporation and FortisUS Inc.
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
OATT	Open Access Transmission Tariff
PNM	Public Service Company of New Mexico

PPFAC	Purchased Power and Fuel Adjustment Clause
REC	Renewable Energy Credit
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas

RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
Springerville Coal Handling Facilities	Coal handling facilities at Springerville used by all four Springerville units
Springerville Coal Handling Facilities Leases	Leases for coal handling facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 2	Unit 2 of the Springerville Generating Station
Springerville Unit 3	Unit 3 of the Springerville Generating Station
Springerville Unit 4	Unit 4 of the Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
TEP Credit Agreement	The TEP Credit Agreement consists of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds.
Therm	A unit of heating value equivalent to 100,000 Btus
Tri-State	Tri-State Generation and Transmission Association, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy
UNS Energy	UNS Energy Corporation
UNS Energy affiliates	Affiliated subsidiaries of UNS Energy including UNS Electric, Inc., UNS Gas, Inc., and Southwest Energy Solutions, Inc.
UNS Gas	UNS Gas, Inc., an indirect wholly-owned subsidiary of UNS Energy

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FORWARD-LOOKING INFORMATION

This Quarterly Report on Form 10-Q contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. TEP is including the following cautionary statements to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by or for TEP in this Quarterly Report on Form 10-Q. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance and underlying assumptions, and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as anticipates, estimates, expects, intends, plans, predicts, projects, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, TEP disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s expectations, beliefs or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in: Part II, Item 1A. Risk Factors; Part I, Item 2. Management’s Discussion and Analysis; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions; changes in, and compliance with, environmental laws, regulations, decisions and policies that could increase operating and capital costs, reduce generating facility output or accelerate generating facility retirements; regional economic and market conditions which could affect customer growth and energy usage; weather variations affecting energy usage; the cost of debt and equity capital and access to capital markets; the performance of the stock market and changing interest rate environment, which affect the value of our pension and other retiree benefit plan assets and the related contribution requirements and expense; unexpected increases in O&M expense; resolution of pending litigation matters; changes in accounting standards; changes in critical accounting estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

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PART I—FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2014 (Unaudited)	December 31, 2013
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	$4,675,441	$4,467,667
Utility Plant Under Capital Leases	747,158	637,957
Construction Work in Progress	173,022	180,485
Total Utility Plant	5,595,621	5,286,109
Less Accumulated Depreciation and Amortization	(1,909,448)	(1,826,977)
Less Accumulated Amortization of Capital Lease Assets	(531,159)	(514,677)
Total Utility Plant—Net	3,155,014	2,944,455
Investments and Other Property		
Investments in Lease Equity	36,086	36,194
Other	36,201	33,488
Total Investments and Other Property	72,287	69,682
Current Assets		
Cash and Cash Equivalents	28,208	25,335
Accounts Receivable—Customer	110,906	80,211
Unbilled Accounts Receivable	49,743	34,369
Allowance for Doubtful Accounts	(5,136)	(4,825)
Accounts Receivable—Due from Affiliates	3,281	6,064
Materials and Supplies	80,475	75,200
Deferred Income Taxes—Current	111,593	70,722
Fuel Inventory	39,027	44,027
Regulatory Assets—Current	66,877	42,555
Derivative Instruments	699	2,137
Other	13,923	12,923
Total Current Assets	499,596	388,718
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	162,872	141,030
Derivative Instruments	212	167
Other Assets	20,587	19,233
Total Regulatory and Other Assets	183,671	160,430
Total Assets	$3,910,568	$3,563,285

See Notes to Condensed Consolidated Financial Statements.

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2014 (Unaudited)	December 31, 2013
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$1,017,778	$925,923
Capital Lease Obligations	68,424	131,370
Long-Term Debt	1,372,369	1,223,070
Total Capitalization	2,458,571	2,280,363
Current Liabilities		
Current Obligations Under Capital Leases	191,951	186,056
Borrowings Under Revolving Credit Facility	35,000	—
Accounts Payable—Trade	83,571	88,556
Accounts Payable—Due to Affiliates	4,099	9,153
Accrued Taxes Other than Income Taxes	53,230	34,485
Accrued Employee Expenses	18,134	24,454
Regulatory Liabilities—Current	37,125	23,701
Accrued Interest	20,043	22,785
Customer Deposits	20,370	21,354
Derivative Instruments	6,664	5,531
Other	8,420	9,244
Total Current Liabilities	478,607	425,319
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	509,062	428,103
Regulatory Liabilities—Noncurrent	302,912	263,270
Pension and Other Postretirement Benefits	79,911	84,936
Derivative Instruments	3,393	5,161
Other	78,112	76,133
Total Deferred Credits and Other Liabilities	973,390	857,603
Commitments, Contingencies & Environmental Matters (Note 5)		
Total Capitalization and Other Liabilities	$3,910,568	$3,563,285

See Notes to Condensed Consolidated Financial Statements.
(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

Three Months Ended September 30, 2014	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
(Unaudited) Thousands of Dollars			(Unaudited) Thousands of Dollars	
		Operating Revenues		
$316,387	$310,632	Electric Retail Sales	$760,192	$739,147
37,053	26,563	Electric Wholesale Sales	111,692	90,503
33,971	34,044	Other Revenues	92,658	93,603
387,411	371,239	Total Operating Revenues	964,542	923,253
		Operating Expenses		
89,199	82,065	Fuel	225,163	247,417
49,902	42,477	Purchased Energy	125,423	89,815
5,222	4,940	Transmission and Other PPFAC Recoverable Costs	12,683	7,535
(5,376)	(7,992)	Increase (Decrease) to Reflect PPFAC Recovery Treatment	(20,167)	(5,079)
138,947	121,490	Total Fuel and Purchased Energy	343,102	339,688
112,667	79,335	Operations and Maintenance	273,784	239,170
31,966	30,311	Depreciation	93,857	87,729
6,973	6,118	Amortization	21,449	24,393
11,960	10,808	Taxes Other Than Income Taxes	35,800	32,916
302,513	248,062	Total Operating Expenses	767,992	723,896
84,898	123,177	Operating Income	196,550	199,357
		Other Income (Deductions)		
7	6	Interest Income	181	14
2,024	1,466	Other Income	6,123	3,904
(7,170)	(2,776)	Other Expense	(11,979)	(7,493)
(504)	731	Appreciation (Depreciation) in Fair Value of Investments	375	1,864
(5,643)	(573)	Total Other Income (Deductions)	(5,300)	(1,711)
		Interest Expense		
15,579	13,848	Long-Term Debt	45,326	42,412
1,202	6,323	Capital Leases	9,048	18,821
104	82	Other Interest Expense	557	(86)
(850)	(644)	Interest Capitalized	(2,878)	(1,671)
16,035	19,609	Total Interest Expense	52,053	59,476
63,220	102,995	Income Before Income Taxes	139,197	138,170
23,576	38,828	Income Tax Expense	51,656	41,737
$39,644	$64,167	Net Income	$87,541	$96,433

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Three Months Ended September 30, 2014	Three Months Ended September 30, 2013		Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
(Unaudited)			(Unaudited)	
Thousands of Dollars			Thousands of Dollars	
		Comprehensive Income		
$39,644	$64,167	Net Income	$87,541	$96,433
		Other Comprehensive Income		
		Net Changes in Fair Value of Cash Flow Hedges:		
697	700	net of income tax expense of $450 and $458		
		net of income tax expense of $1,117 and $1,412	1,672	2,156
		Supplemental Executive Retirement Plan (SERP) Benefit Amortization:		
25	68	net of income tax expense of $16 and $42		
		net of income tax expense of $46 and $127	74	205
722	768	Total Other Comprehensive Income, Net of Taxes	1,746	2,361
$40,366	$64,935	Total Comprehensive Income	$89,287	$98,794

See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine Months Ended September 30,	
	2014	2013
	(Unaudited)	
	Thousands of Dollars	
Net Income	$87,541	$96,433
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities		
Depreciation Expense	93,857	87,729
Amortization Expense	21,449	24,393
Amortization of Deferred Debt-Related Costs included in Interest Expense	1,959	1,831
Use of Renewable Energy Credits for Compliance	15,129	11,766
Deferred Income Taxes	53,991	53,381
Pension and Retiree Expense	10,236	14,909
Pension and Retiree Funding	(12,989)	(26,118)
Share-Based Compensation Expense	5,010	2,239
Allowance for Equity Funds Used During Construction	(4,983)	(2,923)
LFCR Revenue	(8,350)	—
Decrease to Reflect PPFAC Recovery	(20,167)	(5,079)
Fortis Acquisition Direct Customer Benefit	18,870	—
PPFAC Reduction - 2013 TEP Rate Order	—	3,000
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately		
Accounts Receivable	(45,758)	(41,227)
Materials and Fuel Inventory	(274)	14,955
Accounts Payable	(472)	(8,678)
Income Taxes	(25)	(10,681)
Interest Accrued	(3,849)	1,008
Taxes Other Than Income Taxes	18,745	17,405
Other	(8,652)	19,836
Net Cash Flows – Operating Activities	221,268	254,179
Cash Flows from Investing Activities		
Capital Expenditures	(227,153)	(180,451)
Purchase of Intangibles—Renewable Energy Credits	(22,047)	(17,552)
Return of Investments in Springerville Lease Debt	—	9,104
Restricted Cash Released	—	4,500
Other, net	12,883	4,656
Net Cash Flows—Investing Activities	(236,317)	(179,743)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facility	190,000	78,000
Repayments of Borrowings Under Revolving Credit Facility	(155,000)	(78,000)
Proceeds from Issuance of Long-Term Debt	149,168	—
Payments of Capital Lease Obligations	(165,145)	(99,621)
Dividends Paid to UNS Energy	—	(20,000)
Payment of Debt Issue/Retirement Costs	(1,652)	(1,022)
Other, net	551	1,250
Net Cash Flows—Financing Activities	17,922	(119,393)

Net Increase (Decrease) in Cash and Cash Equivalents	2,873	(44,957)
Cash and Cash Equivalents, Beginning of Year	25,335	79,743
Cash and Cash Equivalents, End of Period	$28,208	$34,786

See Note 8 for supplemental cash flow information.
See Notes to Condensed Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDER'S EQUITY

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
	(Unaudited) Thousands of Dollars				
Balances at December 31, 2013	$888,971	$(6,357)	$49,185	$ (5,876)	$925,923
Net Income			87,541		87,541
Other Comprehensive Income, net of taxes				1,746	1,746
Other	2,568				2,568
Balances at September 30, 2014	$891,539	$(6,357)	$136,726	$ (4,130)	$1,017,778

See Notes to Condensed Consolidated Financial Statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

Tucson Electric Power Company (TEP) is a regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agricultural Improvement and Power District (SRP). TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis), which is a leader in the North American electric and gas utility business.

FORTIS ACQUISITION OF UNS ENERGY

On December 11, 2013, UNS Energy, the parent of TEP, announced that it had entered into an Agreement and Plan of Merger (Merger) to be acquired by Fortis for $60.25 per share of UNS Energy common stock in cash. The acquisition contemplated by this agreement was completed effective August 15, 2014.

Prior to completion of the Merger, UNS Energy obtained the approval of its shareholders, the Federal Energy Regulatory Commission (FERC), and the Arizona Corporation Commission (ACC). The ACC's approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling $19 million over five years: approximately $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- TEP, along with UNS Energy and its other affiliated subsidiaries, will adopt certain ring-fencing and corporate governance provisions;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for a period of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital. The ratios used to determine the dividend restrictions will be calculated each calendar year and reported to the ACC annually beginning on April 1, 2016; and
- Fortis making an equity investment totaling $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the close of the Merger, Fortis exceeded the investment requirement by contributing $37 million to UNS Energy on August 15, 2014 and $200 million to UNS Energy on October 10, 2014. On October 10, 2014, UNS Energy contributed $175 million of the investment to TEP.

As a result of the Merger being completed, TEP recorded approximately $15 million through August 2014 as its allocated share of merger-related expenses, in addition to the customer bill credits discussed above. Merger-related expenses include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards.

SHARE-BASED COMPENSATION EXPENSE

Completion of the Merger resulted in accelerated vesting and expense recognition of all outstanding non-vested UNS Energy share-based awards that would otherwise have been recognized over remaining vesting periods through February 2017. TEP recognized approximately $2 million of expense in the third quarter of 2014 due to the accelerated vesting of the awards. TEP recorded total share-based compensation expense of $4 million for the three months ended September 30, 2014 and $1 million for the three months ended September 30, 2013. For the nine months ended September 30, 2014 and 2013, TEP recorded $5 million and $3 million of share-based compensation expense, respectively. In August 2014, UNS Energy settled all outstanding share-based compensation awards in cash.

BASIS OF PRESENTATION

We prepared our condensed consolidated financial statements according to generally accepted accounting principles in the United States of America (GAAP) and the Securities and Exchange Commission's (SEC) interim reporting requirements. These condensed consolidated financial statements exclude some information and footnotes required by GAAP and the SEC for annual financial statement reporting. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and footnotes in our 2013 Annual Report on Form 10-K.

The condensed consolidated financial statements are unaudited, but, in management's opinion, include all recurring adjustments necessary for a fair presentation of the results for the interim periods presented. Because weather and other factors cause seasonal fluctuations in sales, our quarterly results are not indicative of annual operating results. TEP did not reflect the impacts of acquisition accounting in its financial statements. All adjustments of assets and liabilities to fair value and the resultant goodwill associated with the Merger were recorded by FortisUS Inc., a wholly owned subsidiary of Fortis.

As a result of the Fortis Merger, TEP has elected to change its method of reporting cash flows from the direct to the indirect method to conform to the presentation method elected by Fortis. Certain amounts from prior periods have been reclassified to conform to the current period presentation.

REVISION OF PRIOR PERIOD BALANCE SHEETS

TEP revised its December 31, 2013 balance sheet to correct an error in the classification of capital lease obligations and related deferred income taxes. The correction increased current capital lease obligations and decreased noncurrent capital lease obligations by $18 million and increased current deferred tax assets and noncurrent deferred tax liabilities by $7 million. We do not believe the misclassification was material to the previously issued financial statements.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2014, we adopted accounting guidance that:

- requires an entity to recognize and disclose in the financial statements its obligation from a joint and several liability arrangement as the sum of the amount the entity agreed with its co-obligors that it will pay and any additional amount the entity expects to pay on behalf of its co-obligors. The adoption of this guidance did not have a material impact on our disclosures, financial condition, results of operations, or cash flows.
- impacts the financial statement presentation of unrecognized tax benefits when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. Although adoption and prospective application of this guidance impacted how such items are classified on our balance sheets, such change was not material. Additionally, there were no material changes in our results of operations or cash flows.

NOTE 2. REGULATORY MATTERS

The ACC and the FERC each regulate portions of the utility accounting practices and rates of TEP.

The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, transactions with affiliated parties, and other utility matters. The ACC also enacts other regulations and policies that can affect business decisions and accounting practices. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

COST RECOVERY MECHANISMS

Purchased Power and Fuel Adjustment Clause

In April 2014, the ACC approved a Purchased Power and Fuel Adjustment Clause (PPFAC) rate for TEP of 0.10 cents per kWh for the period May through September 2014 and 0.50 cents per kWh for the period October 2014 through March 2015. TEP's PPFAC rate was a credit of approximately 0.14 cents per kWh for the period July 2013 through April 2014.

San Juan Mine Fire Insurance Proceeds

In September 2011, a fire at the underground mine providing coal to San Juan Generating Station (San Juan) caused interruptions to mining operations and resulted in increased fuel costs. The 2013 TEP Rate Order required TEP to defer incremental fuel costs of $10 million from recovery under the PPFAC pending final resolution of an insurance claim by the San Juan Coal Company and distribution of insurance proceeds to San Juan participants. As of September 30, 2014, TEP has received insurance settlement proceeds of $8 million and expects to receive substantially all of the outstanding balance in the fourth quarter. The proceeds offset the deferred costs and are reflected in our cash flow statements as an other operating cash receipt. TEP expects to recover any remaining fuel costs, not reimbursed by insurance, through its PPFAC.

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Environmental Compliance Adjustor
The 2013 TEP Rate Order provided an Environmental Compliance Adjustor (ECA) to recover the return on and of qualified investments to comply with environmental standards required by federal or other governmental agencies. The ECA rate of 0.0049 cents per kWh became effective on May 1, 2014. TEP expects to recognize ECA revenues of less than $1 million in 2014.
Energy Efficiency Standards
TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's Energy Efficiency (EE) Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs as well as a performance incentive. In the first nine months of 2014, TEP recorded a DSM performance incentive of $2 million that is included in Electric Retail Sales in the TEP Income Statement.
Lost Fixed Cost Recovery Mechanism
The Lost Fixed Cost Recovery (LFCR) mechanism provides recovery of certain non-fuel costs that would go unrecovered due to lost retail kWh sales as a result of implementing ACC approved EE programs and distributed generation (DG) targets. For recovery of lost fixed costs, TEP is required to file an annual LFCR adjustment request with the ACC for costs related to the prior year, and recovery is subject to a year-over-year cap of 1% of the company's total retail revenues.
TEP recorded, in Electric Retail Sales, LFCR revenues of $8 million in the first nine months of 2014 related to reductions in retail kWh sales for 2013 and 2014. We recognize LFCR revenue when verifiable regardless of when the lost retail kWh sales occur.
The ACC approved TEP's annual LFCR recovery request for lost fixed costs incurred in 2013 of approximately $5 million. The approved rates, of approximately 0.41% of retail revenue for EE and approximately 0.31% of retail revenue for DG, became effective August 2014.

NOTE 3. RELATED PARTY TRANSACTIONS
TEP engages in various transactions with affiliated subsidiaries of UNS Energy including UNS Electric, Inc., (UNS Electric), UNS Gas, Inc. (UNS Gas) and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy affiliates). These transactions include sales and purchases of power, common cost allocations, and the provision of corporate and other labor related services. Additionally, TEP and UNS Electric are planning the joint purchase of a generating station unit. See Note 6.
The following table summarizes related party transactions:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Wholesale Sales - TEP to UNS Electric [1]	$2	$—	$3	$1
Wholesale Sales - UNS Electric to TEP [1]	2	—	3	1
Control Area Services - TEP to UNS Electric [2]	1	1	2	3
Common Costs - TEP to UNS Energy Affiliates [3]	3	3	10	9
Supplemental Workforce - SES to TEP [4]	4	4	12	11
Corporate Services and Other Labor Charges - TEP to UNS Energy Affiliates [5]	3	4	7	10
Corporate Services - UNS Energy Affiliates to TEP [5]	—	—	1	1

(1) TEP and UNS Electric sell power to each other at prevailing market prices.
(2) TEP charges UNS Electric for control area services under a FERC-accepted Control Area Services Agreement.
(3)

Common costs (systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. Management believes this method of allocation is reasonable.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(4) SES provides supplemental workforce and meter-reading services to TEP. Amounts are based on costs of services performed, and management believes that the charges for the services are reasonable.

(5) All Corporate Services (finance, accounting, tax, legal and information technology) and other labor services are directly assigned to the benefiting entity at a fully burdened cost when possible; other costs are allocated using the Massachusetts' Formula, an industry accepted method of allocating common costs to affiliated entities.

At September 30, 2014 and December 31, 2013, our Balance Sheets include the following intercompany balances:

	Balances at	
	September 30, 2014	December 31, 2013
	Millions of Dollars	
Receivables from Related Parties		
UNS Electric	$2	$3
UNS Gas	1	2
UNS Energy	—	1
Total Due from Related Parties	$3	$6
Payables to Related Parties		
SES	$3	$2
UNS Electric	1	—
UNS Energy	—	7
Total Due to Related Parties	$4	$9

NOTE 4. DEBT AND CAPITAL LEASE OBLIGATIONS

We summarize below the significant changes to our debt and capital lease obligations from those reported in our 2013 Annual Report on Form 10-K.

SPRINGERVILLE COAL HANDLING FACILITIES CAPITAL LEASE PURCHASE COMMITMENT

In April 2014, TEP notified the owner participants and their lessors that TEP has elected to purchase their undivided ownership interests in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million upon the expiration of the lease term in April 2015. Due to TEP’s purchase commitment, in April of 2014, TEP recorded an increase to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases on its balance sheet in the amount of $109 million, which represented the present value of the total purchase commitment.

TEP previously agreed with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities Leases were not renewed, TEP would exercise the purchase option under those contracts. Upon TEP's purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million, and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. No amounts have been recorded for these commitments from SRP and Tri-State at September 30, 2014.

2014 UNSECURED NOTES ISSUED

In March 2014, TEP issued $150 million of 5.0% unsecured notes due March 2044. TEP may redeem the notes prior to September 15, 2043, with a make-whole premium plus accrued interest. After September 15, 2043, TEP may redeem the notes at par plus accrued interest. TEP used the net proceeds to repay approximately $90 million on the outstanding borrowings under the revolving credit facility with the remaining proceeds used for general corporate purposes. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding.

TEP CREDIT AGREEMENT

The TEP Credit Agreement consists of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds. As of September 30, 2014, there is $149 million available under the revolving credit

facility. The TEP Credit Agreement expires in November 2016. As of October 20, 2014, TEP had $185 million available under its revolving credit facility.

TEP provided, in the second quarter of 2014, a LOC for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. TEP's borrowing capacity under the TEP Credit Agreement is reduced by $15 million until the Gila River transaction closes and the LOC is terminated. See Note 6.

COVENANT COMPLIANCE

At September 30, 2014, we were in compliance with the terms of our loan and credit agreements.

NOTE 5. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS

COMMITMENTS

In addition to those reported in our 2013 Annual Report on Form 10-K, TEP entered into the following long-term commitments through September 30, 2014:

	2014	2015	2016	2017	2018	Thereafter	Total
	Millions of Dollars						
Fuel, Including Transportation	$—	$9	$9	$10	$10	$42	$80
Purchased Power	—	18	—	—	—	—	18
Renewable Power Purchase Agreements (PPA)(2)	6	5	5	5	5	60	86
Capital Lease Obligations(1)	—	120	—	—	—	—	120
Total Purchase Commitments	$6	$152	$14	$15	$15	$102	$304

(1) In April 2014, TEP entered into agreements to purchase certain Springerville Coal Handling Facilities leased interests. See Note 4.

(2) In July 2014, TEP entered into a 20-year PPA with a renewable energy generation facility that achieved commercial operation in July 2014. TEP is obligated to purchase 100% of the output from this facility. The amounts in the table also reflect updated estimated annual production for existing contracts which increased the minimum annual payment obligations.

CONTINGENCIES

Planned Purchase of Gas-Fired Generation Facility

In 2013, TEP and UNS Electric, an affiliate of TEP, entered into an agreement to purchase a gas-fired generation facility. See Note 6.

Claims Related to San Juan Generating Station

San Juan Coal Company (SJCC) operates an underground coal mine in an area where certain gas producers have oil and gas leases with the federal government, the State of New Mexico, and private parties. These gas producers allege that SJCC’s underground coal mine interferes with their operations, reducing the amount of natural gas they can recover. SJCC compensated certain gas producers for any remaining production from wells deemed close enough to the mine to warrant plugging and abandoning them. These settlements, however, do not resolve all potential claims by gas producers in the area. TEP owns 50% of Units 1 and 2 at San Juan Generating Station (San Juan), which represents approximately 20% of the total generation capacity at San Juan, and is responsible for its share of any settlements. TEP cannot estimate the impact of any future claims by these gas producers on the cost of coal at San Juan.

In August 2013, the Bureau of Land Management (BLM) proposed regulations that, among other things, redefine the term “underground mine” to exclude high-wall mining operations and impose a higher surface mine coal royalty on high-wall mining. SJCC utilized high-wall mining techniques at its surface mines prior to beginning underground mining operations in January 2003. If the proposed regulations become effective, SJCC may be subject to additional royalties on coal delivered to San Juan between August 2000 and January 2003 totaling approximately $5 million of which TEP’s proportionate share would approximate $1 million. TEP cannot predict the final outcome of the BLM’s proposed regulations.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint. In August 2014, APS submitted a counteroffer with revised settlement terms. The joint participants have agreed to have the matter stayed until November 2014 to make continued progress toward a final agreement that would resolve this matter without further litigation.

TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. TEP's estimated share of the settlement offer submitted by APS in August 2014 is less than $1 million. TEP cannot predict the final outcome of the claims relating to Four Corners, and, due to the general and non-specific nature of the claims and the indeterminate scope and nature of the injunctive relief sought for this claim, TEP cannot determine estimates of the range of costs at this time.

In May 2013, the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. In December 2013, the coal supplier and Four Corners’ operating agent filed a claim contesting the validity of the assessment on behalf of the participants in Four Corners, who will be liable for their share of any resulting liabilities. TEP’s share of the assessment based on its ownership of Four Corners is approximately $1 million. The New Mexico Taxation and Revenue Department and APS started settlement negotiations in July 2014. TEP cannot predict the outcome or timing of resolution of this claim.

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP’s share of reclamation costs at all three mines is expected to be $44 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The reclamation liability (present value of future liability) recorded was $21 million at September 30, 2014 and $18 million at December 31, 2013.

Amounts recorded for final reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the credit-adjusted risk-free interest rate to be used to discount future liabilities. As these assumptions change, TEP will prospectively adjust the expense amounts for final reclamation over the remaining coal supply agreements’ terms. TEP does not believe that recognition of its final reclamation obligations will be material to TEP in any single year because recognition will occur over the remaining terms of its coal supply agreements.

TEP’s PPFAC allows us to pass through most fuel costs, including final reclamation costs, to customers. Therefore, TEP classifies these costs as a regulatory asset by increasing the regulatory asset and the reclamation liability over the remaining life of the coal supply agreements and recovers the regulatory asset through the PPFAC as final mine reclamation costs are paid to the coal suppliers.

Discontinued Transmission Project

TEP and UNS Electric had initiated a project to jointly construct a 60-mile transmission line from Tucson, Arizona to Nogales, Arizona in response to an order by the ACC to UNS Electric to improve the reliability of electric service in Nogales. At this time, TEP and UNS Electric will not proceed with the project based on the cost of the proposed 345-kV line, the difficulty in reaching agreement with the United States Forest Service on a path for the line, and concurrence by the ACC that recent transmission additions by TEP and UNS Electric support elimination of this project. TEP and UNS Electric plan to keep the path approved in the line siting matter in contemplation of using a greater part of the route to serve future customers and to address reliability needs. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from the FERC before seeking rate recovery from the ACC. In 2012, TEP wrote off $5 million of the capitalized costs believed not probable of recovery and recorded a regulatory asset of $5 million for the balance deemed probable of recovery in TEP's next FERC rate case.

Performance Guarantees

The participants in each of the remote generating stations in which TEP participates, including TEP, have guaranteed certain performance obligations of the other participants. Specifically, in the event of payment default of a participant, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generating capacity of the defaulting participants. As of September 30, 2014, there have been no such payment defaults under any of the remote generating station agreements. TEP's joint participation agreements expire in 2016 through 2046.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

In February 2012, the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from power plants. Based on the EPA's final Mercury and Air Toxics (MATS) rules, additional emission control equipment will be required by April 2015. TEP, as operator of Springerville and Sundt, and the operator of Navajo have received extensions until April 2016 to comply with the MATS rules. TEP's share of the estimated costs to comply with the MATS rules includes the following:

Estimated Mercury Emissions Control Costs:	Navajo	Springerville[1]
	Millions of Dollars	
Capital Expenditures	$1	$5
Annual O&M Expenses	1	1

(1) Total capital expenditures and annual O&M expenses represent amounts for both Springerville Units 1 & 2, with estimated costs split equally between the two units. TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases in January 2015; after the completion of such purchases, third party owners will be responsible for 50.5% of environmental costs attributable to Springerville Unit 1. TEP will continue to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

TEP expects Four Corners, Sundt, and San Juan's current emission controls to be adequate to comply with the EPA's MATS rules. A study determined that Four Corners' emission controls are adequate. Therefore, TEP expects no additional capital expenditures or O&M expenses will be incurred to comply. Although expected to be compliant, Sundt would be required to install additional monitoring equipment, at an estimated cost of less than $1 million, to continue to burn coal after the MATS rules become effective.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rules call for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants. In the western U.S., Regional Haze BART determinations have focused on controls for NOx, often resulting in a requirement to install selective catalytic reduction (SCR). Complying with the EPA's BART rules, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. BART provisions of Regional Haze Rules requiring emission control upgrades do not apply to Springerville because the BART rules apply to plants built prior to Springerville. TEP cannot predict the ultimate outcome of these matters. TEP's estimated costs involved in meeting these rules are:

Estimated NOx Emissions Control Costs:	Navajo [1]	San Juan [2]	Four Corners [3]	Sundt [4]

	Millions of Dollars			
Capital Expenditures	$42	$35	$35	$12
Annual O&M Expenses	1	1	2	5-6

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(1) In August 2014, the EPA published a final rule approving a better-than-BART plan wherein: one unit at Navajo will be shut down by 2020; SCR (or the equivalent) will be installed on the remaining two units by 2030; and conventional coal-fired generation will cease by December 2044. In addition, the installation of SCR technology could increase particulates which may require that baghouses be installed. TEP owns 7.5% of Navajo. TEP's share of the capital cost of baghouses in addition to the SCR costs reflected in the table above is approximately $43 million with O&M on the baghouses expected to be less than $1 million per year.

(2) In October 2014, the EPA published a final rule approving a state plan covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of selective non-catalytic reduction (SNCR) on Units 1 and 4 by January 2016. Corresponding to that action, the EPA withdrew the previously applicable FIP addressing the same requirements. Prior to the shutdown of any units in San Juan, PNM must obtain New Mexico Public Regulation Commission approval. If Unit 2 is retired early, TEP expects to request ACC approval to recover all costs associated with the early closure of the unit. TEP owns 50% of San Juan Unit 2. At September 30, 2014, the net book value of TEP's share in San Juan Unit 2 was $111 million.

(3) In December 2013, APS, on behalf of the co-owners of Four Corners, notified the EPA that they have chosen an alternative BART compliance strategy; as a result, APS closed Units 1, 2, and 3 in December 2013 and has agreed to the installation of SCR on Units 4 & 5 by July 2018. TEP owns 7% of Four Corners Units 4 and 5.

(4) In June 2014, the EPA issued a final rule that would require TEP to either (i) install SNCR and dry sorbent injection technology on Unit 4 by mid-2017 or (ii) eliminate the use of coal by the end of 2017 as a better-than-BART alternative. TEP is required to notify the EPA of its decision by March 2017. At September 30, 2014, the net book value of the Sundt coal handling facilities was $17 million. If the coal handling facilities are retired early, TEP expects to request ACC approval to recover all the remaining costs of the coal handling facilities.

NOTE 6. PLANNED PURCHASE OF GAS-FIRED GENERATION FACILITY

In December 2013, TEP and UNS Electric, an affiliate of TEP, entered into a purchase agreement with a subsidiary of Entegra to purchase Gila River Unit 3 for $219 million, subject to certain closing adjustments. Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW, is located in Gila Bend, Arizona. TEP expects to purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million, and UNS Electric expects to purchase the remaining 25% undivided interest (137 MW) for approximately $55 million. In October 2014, the FERC issued an order authorizing the transaction. The closing of the transaction remains subject to certain other closing conditions and finalizing various closing documents. TEP and UNS Electric expect the transaction to close in December 2014.

In June 2014, TEP provided a letter of credit (LOC) for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. The seller is entitled to draw upon the LOC and apply such amount as liquidated damages if it has validly terminated the purchase agreement as a result of misrepresentations by TEP and UNS Electric or the failure of TEP and UNS Electric to close the transaction when the closing conditions have been satisfied. Upon the close of the transaction, the LOC will be canceled. In August 2014, Entegra filed a prepackaged Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the District of Delaware. In September 2014, Entegra's Chapter 11 bankruptcy plan was confirmed. TEP does not expect the bankruptcy to impact the purchase of Gila River Unit 3.

NOTE 7. EMPLOYEE BENEFIT PLANS

Net periodic benefit plan cost includes the following components:

	Pension Benefits		Other Retiree Benefits	
	Three Months Ended September 30,			
	2014	2013	2014	2013
	Millions of Dollars			

Service Cost	$2	$3	$1	$1
Interest Cost	4	4	—	—
Expected Return on Plan Assets	(5)	(5)	—	—
Actuarial Loss Amortization	1	2	—	—
Net Periodic Benefit Cost	$2	$4	$1	$1

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	Pension Benefits		Other Retiree Benefits	
	Nine Months Ended September 30,			
	2014	2013	2014	2013
	Millions of Dollars			
Service Cost	$7	$8	$3	$3
Interest Cost	12	11	2	2
Expected Return on Plan Assets	(16)	(14)	(1)	(1)
Actuarial Loss Amortization	3	6	—	—
Net Periodic Benefit Cost	$6	$11	$4	$4

NOTE 8. SUPPLEMENTAL CASH FLOW INFORMATION

NON-CASH TRANSACTIONS

In April 2014, TEP recorded an increase of $109 million to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases due to TEP's commitment to purchase leased interests in April 2015. See Note 4.

In August 2013, TEP recorded an increase of $39 million to both Utility Plant Under Capital Leases and Capital Lease Obligations due to TEP's commitment to purchase leased interests in Springerville Unit 1 in January 2015.

In March 2013, TEP issued $91 million of tax-exempt bonds and used the proceeds to redeem debt using a trustee. Since the cash flowed through a trust account, the issuance and redemption of debt resulted in a non-cash transaction.

NOTE 9. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

We categorize our assets and liabilities accounted for at fair value into the three-level hierarchy based on inputs used to determine the fair value. Level 1 inputs are unadjusted quoted prices for identical assets or liabilities in an active market. Level 2 inputs include quoted prices for similar assets or liabilities, quoted prices in non-active markets, and pricing models whose inputs are observable, directly or indirectly. Level 3 inputs are unobservable and supported by little or no market activity. Transfers between levels are recorded at the end of a reporting period. There were no transfers between levels in the periods presented.

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE ON A RECURRING BASIS

The following tables present, by level within the fair value hierarchy, TEP’s assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets[5]	Net Amount
	September 30, 2014 Millions of Dollars					
Assets						
Cash Equivalents[1]	$10	$10	$—	$—	$—	$10
Restricted Cash[1]	2	2	—	—	—	2
Rabbi Trust Investments[2]	25	—	25	—	—	25
Energy Contracts - Regulatory Recovery[3]	1	—	1	—	(1)	—
Total Assets	38	12	26	—	(1)	37
Liabilities						
Energy Contracts - Regulatory Recovery[3]	(5)	—	(2)	(3)	1	(4)
Energy Contracts - Cash Flow Hedge[3]	(1)	—	—	(1)	—	(1)
Interest Rate Swaps[4]	(4)	—	(4)	—	—	(4)
Total Liabilities	(10)	—	(6)	(4)	1	(9)
Net Total Assets (Liabilities)	$28	$12	$20	$(4)	$—	$28

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets[5]	Net Amount
	December 31, 2013 Millions of Dollars					
Assets						
Cash Equivalents[1]	$—	$—	$—	$—	$—	$—
Restricted Cash[1]	2	2	—	—	—	2
Rabbi Trust Investments[2]	22	—	22	—	—	22
Energy Contracts - Regulatory Recovery[3]	2	—	1	1	(1)	1
Total Assets	26	2	23	1	(1)	25
Liabilities						
Energy Contracts - Regulatory Recovery[3]	(2)	—	—	(2)	1	(1)
Energy Contracts - Cash Flow Hedge[3]	(1)	—	—	(1)	—	(1)
Interest Rate Swaps[4]	(7)	—	(7)	—	—	(7)
Total Liabilities	(10)	—	(7)	(3)	1	(9)
Net Total Assets (Liabilities)	$16	$2	$16	$(2)	$—	$16

(1) Cash Equivalents and Restricted Cash represent amounts held in money market funds and certificates of deposit valued at cost, including interest, which approximates fair market value. Cash Equivalents are included in Cash and

Cash Equivalents on the balance sheets. Restricted Cash is included in Investments and Other Property – Other on the balance sheets.

(2) Rabbi Trust Investments include amounts related to deferred compensation and Supplement Executive Retirement Plan (SERP) benefits held in mutual and money market funds valued at quoted prices traded in active markets. These investments are included in Investments and Other Property – Other on the balance sheets.

(3) Energy Contracts include gas swap agreements (Level 2), power options (Level 2), gas options (Level 3), and forward power purchase and sales contracts (Level 3) entered into to reduce exposure to energy price risk. These contracts are included in Derivative Instruments on the balance sheets. The valuation techniques are described below.

(4) Interest Rate Swaps still held are valued based on the 6-month London Interbank Offered Rate (LIBOR). An interest rate swap valued based on the Securities Industry and Financial Markets Association Municipal swap index matured in September 2014. These interest rate swaps are included in Derivative Instruments on the balance sheets.

(5) All energy contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We have presented the effect of offset by counterparty; however, we present derivatives on a gross basis on the balance sheets.

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DERIVATIVE INSTRUMENTS

We enter into various derivative and non-derivative contracts to reduce our exposure to energy price risk associated with our gas and purchased power requirements. The objectives for entering into such contracts include: creating price stability; meeting load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC.

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability or use quoted prices in an inactive market, we categorize the instrument in Level 2. We categorize derivatives in Level 3 when we use an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices we obtain quotes from brokers, major market participants, exchanges, or industry publications and rely on our own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms such as non-standard time blocks and non-standard delivery points. In these cases, we apply adjustments based on historical price curve relationships, transmission, and line losses.

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves. In the first half of 2013, we also used this pricing model to value our power options.

We also consider the impact of counterparty credit risk using current and historical default and recovery rates, as well as our own credit risk using credit default swap data.

The inputs and our assessments of the significance of a particular input to the fair value measurements require judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. We review the assumptions underlying our price curves monthly.

Cash Flow Hedges

We enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. The interest rate swap agreements expire through January 2020. We also have a power purchase swap to hedge the cash flow risk associated with a long-term power supply agreement. The power purchase swap agreement expires in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities and amounts reclassified to earnings are reported in the statements of other comprehensive income and Note 11. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $2 million.

Financial Impact of Energy Contracts

We record unrealized gains and losses on energy contracts that are recoverable through the PPFAC on the balance sheets as a regulatory asset or a regulatory liability rather than reporting the transaction in the income statements or in the statements of other comprehensive income, as shown in following tables:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets)/Liabilities	$(6)	$(1)	$(4)	$(2)

Realized gains and losses on settled contracts are fully recoverable through the PPFAC. At September 30, 2014, we have energy contracts that will settle through the third quarter of 2017.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Derivative Volumes

The volumes associated with our energy contracts were as follows:

	September 30, 2014	December 31, 2013
Power Contracts GWh	842	779
Gas Contracts GBtu	20,595	9,615

Level 3 Fair Value Measurements

The following table provides quantitative information regarding significant unobservable inputs in TEP's Level 3 fair value measurements:

	Valuation Approach	Fair Value at September 30, 2014 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
		Millions of Dollars				
Forward Power Contracts	Market approach	$—	$(3)	Market price per MWh	$27.50	$43.50
Gas Option Contracts	Option model	—	(1)	Market price per MMbtu	$3.67	$4.24
				Gas volatility	24.88%	40.62%
Level 3 Energy Contracts		$—	$(4)			

	Valuation Approach	Fair Value at December 31, 2013 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
		Millions of Dollars				
Forward Power Contracts	Market approach	$—	$(3)	Market price per MWh	$27.00	$48.25
Gas Option Contracts	Option model	1	—	Market price per MMbtu	$3.88	$4.32
				Gas volatility	25.05%	35.07%
Level 3 Energy Contracts		$1	$(3)			

Changes in one or more of the unobservable inputs could have a significant impact on the fair value measurement depending on the magnitude of the change and the direction of the change for each input. The impact of changes to fair value, including changes from unobservable inputs, are subject to recovery or refund through the PPFAC mechanism and are reported as a regulatory asset or regulatory liability, or as a component of other comprehensive income, rather than in the income statement.

The following tables present a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended September 30, 2014	2013
	Millions of Dollars	
Balances at June 30	$—	$(1)
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(4)	(1)

Settlements	—	—
Balances at September 30	$(4)	$(2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/(Liabilities) Still Held at the End of the Period	$(2)	$—

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Balances at December 31	$(2)	$—
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(3)	(2)
Settlements	1	—
Balances at September 30	$(4)	$(2)
Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses) Relating to Assets/(Liabilities) Still Held at the End of the Period	$(2)	$(1)

CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. We enter into contracts for the physical delivery of energy and gas which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and subsequent measurement at fair value.

We have contractual agreements for energy procurement and hedging activities that contain certain provisions requiring each company to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit limits provided to the Regulated Utilities; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, we would have to provide certain credit enhancements in the form of cash or LOCs to fully collateralize our exposure to these counterparties.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

Material adverse changes could trigger credit risk-related contingent features. At September 30, 2014, the value of derivative instruments in a net liability position under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $17 million. At September 30, 2014 , TEP had no cash collateral posted and less than $1 million LOCs as credit enhancements with its counterparties and did not hold any collateral from its counterparties. The additional collateral to be posted if credit-risk contingent features were triggered would be $17 million.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

The fair value of a financial instrument is the market price to sell an asset or transfer a liability at the measurement date. We use the following methods and assumptions for estimating the fair value of our financial instruments:

- The carrying amounts of our current maturities of long-term debt and amounts outstanding under our credit agreements approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For Investment in Lease Equity, we estimate the price at which an investor would realize a target internal rate of return. Our estimates include: the mix of debt and equity an investor would use to finance the purchase; the cost of debt; the required return on equity; and income tax rates. The estimate assumes a residual value based on an appraisal of Springerville Unit 1 conducted in 2011. No impairment has been recorded as TEP expects to recover the full carrying value in retail rates.
- For Long-Term Debt, we use quoted market prices, when available, or calculate the present value of remaining cash flows at the balance sheet date. When calculating present value, we use current market rates for bonds with similar

characteristics such as credit rating and time-to-maturity. We consider the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. We also incorporate the impact of our own credit risk using a credit default swap rate.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The carrying values recorded on the balance sheets and the estimated fair values of our financial instruments include the following:

		September 30, 2014		December 31, 2013	
	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
		Millions of Dollars			
Assets:					
Investment in Lease Equity	Level 3	$36	$26	$36	$25
Liabilities:					
Long-Term Debt	Level 2	1,372	1,444	1,223	1,214

NOTE 10. INCOME TAXES

Income tax expense differs from the amount of income tax determined by applying the United States statutory federal income tax rate of 35% to pre-tax income due to the following:

	Three Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Federal Income Tax Expense at Statutory Rate	$22	$36
State Income Tax Expense, Net of Federal Deduction	3	5
Federal/State Tax Credits	(2)	(1)
Other	1	(1)
Total Federal and State Income Tax Expense	$24	$39

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Federal Income Tax Expense at Statutory Rate	$49	$48
State Income Tax Expense, Net of Federal Deduction	6	6
Federal/State Tax Credits	(4)	(2)
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	—	(11)
Other	1	1
Total Federal and State Income Tax Expense	$52	$42

Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset

Renewable energy assets are eligible for investment tax credits. We reduce the income tax basis of those qualifying assets by half of the related investment tax credit. Historically, the difference between the income tax basis of the assets and the book basis under GAAP was recorded as a deferred tax liability with an offsetting charge to income tax expense in the year the qualifying asset was placed in service. In June 2013, we recorded a regulatory asset and corresponding reduction of income tax expense of $11 million to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. The regulatory asset will be amortized as income tax expense as the qualifying assets are depreciated.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

NOTE 11. RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME BY COMPONENT
The reclassifications from Accumulated Other Comprehensive Income (AOCI) by component are as follows:

Details About Accumulated Other Comprehensive Income Components	Amount Reclassified from Other Comprehensive Income				Affected Line Item in the Income Statement
	Three Months Ended September 30,		Nine Months Ended September 30,		
	2014	2013	2014	2013	
	Thousands of Dollars				
Realized Losses on Cash Flow Hedges					
Interest Rate Swaps - Debt	$(291)	$(296)	$(882)	$(871)	Interest Expense Long-Term Debt
Interest Rate Swaps - Capital Leases	(451)	(612)	(1,649)	(1,820)	Interest Expense Capital Leases
Commodity Contracts	(478)	(556)	(621)	(747)	Purchased Energy/Purchased Power
Income Tax Benefit	546	579	1,238	1,360	
Realized Losses on Cash Flow Hedges, Net of Taxes	(674)	(885)	(1,914)	(2,078)	
Amortization of SERP					
Prior Service Cost and Net Loss	(40)	(110)	(119)	(332)	Other Expense
Income Tax Benefit	15	42	45	127	
Amortization, Net of Taxes	(25)	(68)	(74)	(205)	
Total Reclassifications from Other Comprehensive Income	$(699)	$(953)	$(1,988)	$(2,283)	

NOTE 12. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS
In April 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. This guidance will be effective in the first quarter of 2015. We do not expect the adoption of this guidance to have an impact on the presentation of our financial statements or our disclosures.
In May 2014, the FASB issued an accounting standards update that will eliminate the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replace it with a principles based approach for determining revenue recognition. We will be required to adopt the new guidance retrospectively for annual and interim periods beginning January 1, 2017; early adoption is not permitted. We are evaluating the impact to our financial statements and disclosures.
In August 2014, the FASB issued guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning January 1, 2017; early adoption is permitted. TEP does not expect the adoption of this guidance to have an impact on its disclosures.

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ITEM 2. – MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management’s Discussion and Analysis explains the results of operations, the general financial condition, and the outlook for TEP. It includes the following:

- outlook and strategies;
- operating results during the third quarter and first nine months of 2014 compared with the same periods of 2013;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

OVERVIEW

Tucson Electric Power Company (TEP) is a vertically integrated, regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. In addition, TEP operates Springerville Generating Station (Springerville) Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agricultural Improvement and Power District (SRP). TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis) which is the largest investor-owned gas and electric distribution utility in Canada.

References in this report to "we" and "our" are to TEP.

FORTIS ACQUISITION OF UNS ENERGY

On December 11, 2013, UNS Energy, the parent of TEP, announced that it had entered into an Agreement and Plan of Merger (Merger) to be acquired by Fortis for $60.25 per share of UNS Energy Common Stock in cash. The acquisition contemplated by this agreement was completed effective August 15, 2014.

Prior to completion of the Merger, UNS Energy obtained the approval of its shareholders, the Federal Energy Regulatory Commission (FERC), and the Arizona Corporation Commission (ACC). The ACC's approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling approximately $19 million over five years: $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- TEP, along with UNS Energy and its other affiliated subsidiaries, will adopt certain ring-fencing and corporate governance provisions;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for a period of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital. The ratios used to determine the dividend restrictions will be calculated each calendar year and reported to the ACC annually beginning on April 1, 2016; and
- Fortis making an equity investment totaling $220 million to UNS Energy and its regulated subsidiaries, including TEP. Following the close of the Merger, Fortis exceeded the investment requirement by contributing $37 million to UNS Energy on August 15, 2014 and $200 million to UNS Energy on October 10, 2014. On October 10, 2014, UNS Energy contributed $175 million of the investment to TEP.

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As a result of the Merger being completed, TEP recorded approximately $15 million through August 2014 as its allocated share of merger-related expenses, in addition to the customer bill credits discussed above. Merger-related expenses include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards.

OUTLOOK AND STRATEGIES

TEP's financial prospects and outlook are affected by many factors including: national, regional, and local economic conditions; volatility in the financial markets; environmental laws and regulations; and other regulatory factors. Our plans and strategies include the following:

- Completing the purchases of Gila River Unit 3 and certain interests in Springerville Unit 1, which are both key components of our long-term diversification strategy for our generation portfolio. The focus of our resource strategy is to provide long-term rate stability for our customers, mitigate environmental impacts, comply with regulatory requirements, and leverage our existing utility infrastructure.
- Developing strategic responses to new environmental regulations and potential new legislation, including proposed carbon emission standards to reduce greenhouse gas emissions from existing power plants. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that protect the financial stability of our utility business.
- Strengthening the underlying financial condition of TEP by achieving constructive regulatory outcomes, improving our capital structure and our credit ratings, and promoting economic development in our service territory.
- Focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.
- Developing strategic responses to the evolving utility business that includes renewable energy, distributed generation (DG), and energy efficiency (EE) that protect the financial stability of our business while providing benefits for our customers.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations for the three and nine month periods ended September 30, 2014 and 2013.

Third quarter of 2014 compared with the third quarter of 2013

TEP reported net income of $40 million in the third quarter of 2014 compared with net income of $64 million in the third quarter of 2013. The following factors affected the period over period change in TEP’s results:

- a $39 million pre-tax increase in Base O&M that includes: $19 million for retail customer bill credits agreed to as a condition of closing the Merger; $14 million for TEP's allocated share of merger-related expenses including acquisition transaction fees and accelerated share-based compensation expense recognized under change in control provisions; and $6 million primarily due to higher maintenance expenses at a jointly owned generating station and increased incentive compensation;
- a $3 million pre-tax decrease in retail margin revenues due to a 1.3% decrease in retail kWh sales; and
- a $2 million pre-tax increase in depreciation and amortization expense due to an increase in utility plant in service; offset by
- a $4 million pre-tax decrease in interest expense primarily due to a reduction in the balance of capital lease obligations; and
- a $15 million decrease in income tax expense primarily due to lower pre-tax income. The effective tax rate was approximately 37% in each period.

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Nine months ended September 30, 2014 compared with the nine months ended September 30, 2013

TEP reported net income of $88 million in the first nine months of 2014 compared with net income of $96 million in the first nine months of 2013. The following factors affected the period over period change in TEP's results:

- a $39 million pre-tax increase in Base O&M that includes: $19 million for retail customer bill credits agreed to as a condition of closing the Merger; $15 million for TEP's allocated share of merger-related expenses including acquisition transaction fees and accelerated share-based compensation expense recognized under change in control provisions; and $5 million primarily due to higher maintenance expenses at a jointly owned generating station and increased incentive compensation;
- a $5 million pre-tax increase in depreciation and amortization expense resulting from an increase in asset base in the current period, offset by the impact of lower average depreciation rates as approved in the TEP 2013 Rate Order;
- a $3 million pre-tax increase in taxes other than income taxes due in part to an increase in property tax rates and higher property values; partially offset by
- a $32 million increase in Retail Margin Revenues, primarily due to a non-fuel base rate increase that was effective on July 1, 2013 and includes $8 million of LFCR revenues recorded in the first nine months of 2014 related to reductions in retail kWh sales due to EE programs and DG implemented in 2014 and 2013. See Factors Affecting Results of Operations, 2013 TEP Rate Order, below, and Note 2;
- a $3 million non-recurring pre-tax charge to fuel and purchase energy expense in June 2013 as a result of the 2013 TEP Rate Order;
- a $3 million pretax increase in the margin on long-term wholesale sales due in part to an increase in the market price for wholesale power;
- a $7 million pre-tax decrease in interest expense largely due to a reduction in the balance of capital lease obligations; and
- a $10 million increase in income tax expense based on relatively flat period over period pre-tax earnings due primarily to the impact of an $11 million tax benefit related to a regulatory asset recorded in June 2013 to recover previously recorded income tax expense through future rates. See Note 10.

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Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data during the third quarter of 2014 and 2013:

	Three Months Ended September 30,		Increase (Decrease)	
	2014	2013	Amount	Percent[1]
Energy Sales, kWh (in Millions):				
Electric Retail Sales:				
Residential	1,334	1,354	(20)	(1.5)%
Commercial	642	652	(10)	(1.5)%
Industrial	602	621	(19)	(3.1)%
Mining	287	275	12	4.4%
Other	7	7	—	—%
Total Electric Retail Sales	2,872	2,909	(37)	(1.3)%
Retail Margin Revenues (in Millions):				
Residential	$100	$102	$(2)	(2.0)%
Commercial	61	63	(2)	(3.2)%
Industrial	30	31	(1)	(3.2)%
Mining	11	11	—	—%
Other	—	—	—	NM
Total by Customer Class	202	207	(5)	(2.4)%
LFCR Revenues	2	—	2	NM
Total Retail Margin Revenues (Non-GAAP)[2]	204	207	(3)	(1.4)%
Fuel and Purchased Power Revenues	101	94	7	7.4%
RES, DSM, and ECA Revenues	11	11	—	—%
Total Retail Revenues (GAAP)	$316	$312	$4	1.3%
Average Retail Margin Rate (Cents / kWh):[1]				
Residential	7.50	7.53	(0.03)	(0.4)%
Commercial	9.50	9.62	(0.12)	(1.2)%
Industrial	4.98	4.92	0.06	1.2%
Mining	3.83	3.85	(0.02)	(0.5)%
Other	5.70	5.66	0.04	0.7%
Total Average Retail Margin Rate Excluding LFCR	7.03	7.09	(0.06)	(0.8)%
Average LFCR Rate	0.07	—	—	NM
Total Average Retail Margin Rate Including LFCR	7.10	7.09	0.01	0.1%
Average Fuel and Purchased Power Rate	3.52	3.23	0.29	9.0%
Average RES, DSM, and ECA Rate	0.38	0.36	0.02	5.6%
Total Average Retail Rate	11.00	10.68	0.32	3.0%
Weather Data:				
Cooling Degree Days				
Three Months Ended September 30,	964	1,042	(78)	(7.5)%
10-Year Average	1,000	992	NM	NM

(1) Calculated on un-rounded data and may not correspond exactly to data shown in table.

(2) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information because it demonstrates the underlying revenue trend and

performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales and LFCR revenues available to cover the non-fuel operating expenses of our core utility business.

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Retail kWh Sales and Margin Revenues

TEP's total retail kWh sales decreased by 1.3% in the third quarter of 2014 due in part to (i) a 7.5% decrease in cooling degree days compared with the third quarter of 2013 and (ii) ongoing EE programs and additions to customer-owned solar generation. Total Retail Margin Revenues decreased by $3 million, or 1.4%.

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The table below provides a summary of retail kWh sales, revenues, and weather data during the first nine months of 2014 and 2013:

	Nine Months Ended September 30,		Increase (Decrease)	
	2014	2013	Amount	Percent[1]
Energy Sales, kWh (in Millions):				
Electric Retail Sales:				
Residential	2,987	3,149	(162)	(5.1)%
Commercial	1,671	1,702	(31)	(1.8)%
Industrial	1,599	1,638	(39)	(2.4)%
Mining	850	803	47	5.9%
Other	24	23	1	4.3%
Total Electric Retail Sales	7,131	7,314	(183)	(2.5)%
Retail Margin Revenues (in Millions):				
Residential	$225	$218	$7	3.2%
Commercial	149	144	5	3.5%
Industrial	80	74	6	8.1%
Mining	30	25	5	20.0%
Other	1	1	—	—%
Total by Customer Class	485	461	24	5.2%
LFCR Revenues	8	—	8	NM
Total Retail Margin Revenues (Non-GAAP)[2]	493	461	32	6.9%
Fuel and Purchased Power Revenues	233	245	(12)	(4.9)%
RES, DSM and ECA Revenues	34	33	1	3.0%
Total Retail Revenues (GAAP)	$760	$739	$21	2.8%
Average Retail Margin Rate (Cents / kWh):[1]				
Residential	7.53	6.90	0.63	9.1%
Commercial	8.92	8.43	0.49	5.8%
Industrial	5.00	4.53	0.47	10.4%
Mining	3.53	3.12	0.41	13.1%
Other	5.64	5.65	(0.01)	(0.2)%
Total Average Retail Margin Rate Excluding LFCR	6.80	6.31	0.49	7.8%
Average LFCR Rate	0.11	—	0.11	NM
Total Average Retail Margin Rate Including LFCR	6.91	6.31	0.60	9.5%
Average Fuel and Purchased Power Rate	3.27	3.35	(0.08)	(2.4)%
Average RES, DSM and ECA Rate	0.48	0.45	0.03	6.7%
Total Average Retail Rate	10.66	10.11	0.55	5.4%
Weather Data:				
Cooling Degree Days				
Nine Months Ended September 30,	1,514	1,619	(105)	(6.5)%
10-Year Average	1,477	1,456	NM	NM
Heating Degree Days				
Nine Months Ended September 30,	455	983	(528)	(53.7)%
10-Year Average	820	867	NM	NM

(1) Calculated on un-rounded data and may not correspond exactly to data shown in table.

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(2) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales and LFCR revenues available to cover the non-fuel operating expenses of our core utility business.

Retail kWh Sales and Margin Revenues

TEP's total retail kWh sales decreased by 2.5% in the first nine months of 2014 due in part to: a 6.5% decrease in cooling degree days compared with the first nine months of 2013; a 55.0% decrease in heating degree days during the first three months of 2014 compared with the first three months of 2013; and ongoing EE programs and additions to customer-owned solar generation. Total Retail Margin Revenues increased by $32 million, or 6.9%, due to a Base Rate increase that was effective on July 1, 2013 and $8 million of LFCR revenues recorded in the first nine months of 2014.

Mining kWh sales increased by 5.9% compared with the first nine months of 2013 due in part to an expansion of one of our customer's mines in October 2013.

Wholesale Sales and Transmission Revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Long-Term Wholesale Revenues:				
Long-Term Wholesale Margin Revenues (Non-GAAP)[1]	$2	$2	$8	$5
Fuel and Purchased Power Expense Allocated to Long- Term Wholesale Revenues	4	4	13	14
Total Long-Term Wholesale Revenues	6	6	21	19
Transmission Revenues	4	4	12	11
Short-Term Wholesale Revenues	27	17	79	61
Electric Wholesale Sales (GAAP)	$37	$27	$112	$91

(1) Long-term Wholesale Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Electric Wholesale Sales, which is determined in accordance with GAAP. We believe the change in Long-Term Wholesale Margin Revenues between periods provides useful information because it demonstrates the underlying profitability of TEP’s long-term wholesale sales contracts. Long-Term Wholesale Margin Revenues represents the portion of long-term wholesale revenues available to cover the operating expenses of our core utility business.

Long-Term Wholesale Margin Revenues in the first nine months of 2014 were higher when compared with the first nine months of 2013 due in part to higher market prices for wholesale power.

All revenues from short-term wholesale sales are credited against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars		Millions of Dollars	
Revenue related to Springerville Units 3 and 4[1]	$26	$27	$71	$73
Other Revenue	8	7	22	21

Total Other Revenue	$34	$34	$93	$94

(1) Represents revenues and reimbursements from Tri-State, the lessee of Springerille Unit 3, and SRP, the owner of Springerville Unit 4, to TEP related to the operation of these plants.

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In addition to reimbursements related to Springerville Units 3 and 4, TEP’s other revenues include inter-company revenues from its affiliates, UNS Gas and UNS Electric, for corporate services provided by TEP, and miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees. See Note 3 .

Operating Expenses

Generating Output and Fuel and Purchased Power Expense

Total generating output increased during the third quarter of 2014 when compared with the same period last year due to an unplanned maintenance outage in the third quarter of 2013.

Total generating output decreased during the first nine months of 2014 when compared with the same period last year due in part to maintenance outages.

TEP’s fuel and purchased power expense and energy resources for the quarters ended September 30, 2014 and 2013 are detailed below:

	Generation and Purchased Power		Fuel and Purchased Power Expense	
	Three Months Ended September 30,			
	2014	2013	2014	2013
	Millions of kWh		Millions of Dollars	
Coal-Fired Generation	2,536	2,616	$65	$66
Gas-Fired Generation	464	329	23	14
Utility Owned Renewable Generation	14	8	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4	—	—	1	2
Total Fuel	3,014	2,953	89	82
Total Purchased Power	1,001	875	50	42
Transmission and Other PPFAC Recoverable Costs	—	—	5	5
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	(5)	(8)
Total Resources	4,015	3,828	$139	$121
Less Line Losses and Company Use	(279)	(261)		
Total Energy Sold	3,736	3,567		

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TEP's fuel and purchased power expense and energy resources for the first nine months of 2014 and 2013 are detailed below:

	Generation and Purchased Power		Fuel and Purchased Power Expense	
	Nine Months Ended September 30,			
	2014	2013	2014	2013
	Millions of kWh		Millions of Dollars	
Coal-Fired Generation	6,739	7,726	$170	$208
Gas-Fired Generation	1,009	747	51	34
Utility Owned Renewable Generation	38	31	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4	—	—	4	5
Total Fuel	7,786	8,504	225	247
Total Purchased Power	2,548	1,848	125	90
Transmission and Other PPFAC Recoverable Costs	—	—	13	8
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	(20)	(5)
Total Resources	10,334	10,352	$343	$340
Less Line Losses and Company Use	(678)	(680)		
Total Energy Sold	9,656	9,672		

The table below summarizes average fuel cost per kWh generated or purchased:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	cents per kWh			
Coal	2.55	2.53	2.53	2.70
Gas	5.04	4.35	5.03	4.55
Purchased Power	4.99	4.85	4.92	4.86
All Sources	3.86	3.63	3.76	3.56

O&M

The table below summarizes the items included in O&M expense. Base O&M in the first nine months of 2014 includes $34 million of merger-related expenses and retail customer bill credits.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Base O&M (Non-GAAP)(1)	$96	$57	$218	$179
O&M Recorded in Other Expense	(6)	(2)	(10)	(6)
Reimbursed Expenses Related to Springerville Units 3 and 4	18	18	49	49
Expenses Related to Customer Funded Renewable Energy and DSM Programs(2)	5	6	17	17
Total O&M (GAAP)	$113	$79	$274	$239

(1) Base O&M is a non-GAAP financial measure and should not be considered as an alternative to O&M, which is determined in accordance with GAAP. TEP believes that Base O&M, which is O&M less reimbursed expenses and expenses related to customer-funded renewable energy and DSM programs, provides useful information because it represents the fundamental level of operating and maintenance expense related to our core business.

(2)

Represents expenses related to customer-funded renewable energy and DSM programs; these expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

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The table below summarizes TEP’s pension and other retiree benefit expenses included in Base O&M:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Pension Expense Charged to O&M	$1	$3	$4	$8
Retiree Benefit Expense Charged to O&M	1	1	3	4
Total	$2	$4	$7	$12

FACTORS AFFECTING RESULTS OF OPERATIONS

2013 TEP Rate Order

The provisions of the 2013 TEP Rate Order, which were effective July 1, 2013, include, but are not limited to:

- An annual increase in Base Rates of approximately $76 million.
- A revision in depreciation rates from an average rate of 3.32% to 3.0% for generation and distribution plant regulated by the ACC, primarily due to revised estimates of asset removal costs, which will have the effect of reducing depreciation expense by approximately $11 million annually.
- An LFCR mechanism that allows TEP to recover certain non-fuel costs that would otherwise go unrecovered due to reduced retail kWh sales attributed to EE programs and DG. The LFCR rate will be adjusted annually and is subject to ACC review and a year-over-year cap of 1% of TEP's total retail revenues. TEP filed its first LFCR report with the ACC in May 2014. The report requested recovery of approximately $5 million. The new LFCR rate became effective August 1, 2014. TEP recorded LFCR revenues of $8 million in the first nine months of 2014 related to reductions in retail kWh sales due to EE programs and DG implemented in 2013 and 2014. See Note 2. TEP estimates that it will record total LFCR revenues of approximately $11 million during 2014.
- An ECA mechanism that allows TEP to recover the costs of complying with environmental standards required by federal or other governmental agencies between rate cases. The ECA will be adjusted annually to recover environmental compliance costs and is subject to ACC approval and a cap of $0.00025 per kWh, which approximates 0.25% of TEP's total retail revenues. TEP filed its first ECA report in March 2014 to recover the return on and of qualified investments of approximately $3 million. The ECA rate became effective on May 1, 2014. TEP estimates that it will record total ECA revenues of less than $1 million in 2014.

As required by the 2013 Rate Order, TEP filed a compliance report in July 2014 that outlines its planned purchases of: (i) certain ownership interests in Springerville Unit 1; (ii) 75% of Gila River Unit 3; and (iii) the Springerville Coal Handling Facilities. The report estimates that as a result of these purchases, and the termination of certain lease obligations, TEP's 2014 non-fuel revenue requirement would decline by approximately $36 million. However, when other changes to TEP's rate base, expenses and retail sales levels are considered, we estimate that TEP would have a non-fuel revenue deficiency of approximately $26 million as of December 31, 2014.

See Generating Resources and Springerville Coal Handling Facilities Capital Lease Purchase Commitment, below, for more information.

Generating Resources

At September 30, 2014, approximately 70% of TEP's generating capacity was fueled by coal (Sundt Unit 4 can also be run on natural gas, resulting in 36MW of additional generating capacity). Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is executing current coal reduction strategies and evaluating additional steps for reducing the proportion of coal in its fuel mix. TEP's ability to reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- The outcome of the participant negotiations and mediation regarding San Juan, see Part II, Item. 5 - Other Information, Environmental Matters;
- The outcome of the proposed Clean Power Plan, see Part II, Item. 5 - Other Information, Environmental Matters;

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- TEP's option to permanently convert Sundt Unit 4 to be fueled by natural gas, see Part II, Item. 5 - Other Information, Environmental Matters;
- TEP's future ownership interest in Springerville Unit 1, see Springerville Unit 1, below; and
- The planned purchase of Gila River Unit 3, a combined cycle natural gas plant, see Gila River Generating Station Unit 3, below.

Potential Plant Retirements

TEP periodically files an Integrated Resource Plan (IRP) with the ACC. The IRP provides a view of forecasted energy needs over a long term (15 years) and options being considered to meet those needs. TEP's 2014 IRP reflects planned commitments to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) over the next five years at the Springerville, San Juan, and Sundt Generating Stations. TEP's planning assumptions include potentially retiring certain coal-fired generating facilities at San Juan and coal handling facilities at Sundt earlier than their current estimated useful lives. These facilities currently do not have the requisite emission control equipment to meet proposed EPA regulations. TEP continues to evaluate the potential need to retire these coal-fired generating facilities earlier than the current estimated useful lives, and plans to seek regulatory recovery for amounts that would not be otherwise recovered if and when any assets are retired.

See Part II, Item 5 - Other Information, Environmental Matters, below.

Springerville Unit 1

TEP leases Unit 1 of the Springerville Generating Station and an undivided one-half interest in certain Springerville Common Facilities (collectively Springerville Unit 1) under seven separate lease agreements (Springerville Unit 1 Leases) that are accounted for as capital leases. The leases expire in January 2015 and include fair market value renewal and purchase options. In 2006, TEP purchased a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 MW of capacity.

In 2011, TEP and the owner participants of Springerville Unit 1 completed a formal appraisal procedure to determine the fair market value purchase price of Springerville Unit 1 in accordance with the Springerville Unit 1 Leases. The purchase price was determined to be $478 per kW of capacity based on a capacity rating of 387 MW.

During 2013, TEP agreed to purchase undivided ownership interests in Springerville Unit 1 totaling 35.4%, or 137 MW. The purchase price is the same as the appraisal value of $478 per kW, or approximately $65 million.

Upon the close of these lease option purchases in December 2014 and January 2015, TEP will own 49.5% of Springerville Unit 1, or 192 MW of capacity. Due to TEP’s purchase commitments, TEP recorded an increase to both Utility Plant Under Capital Leases and Capital Lease Obligations on its balance sheet in the aggregate amount of approximately $55 million.

TEP does not expect that its final undivided ownership interest in Springerville Unit 1 will exceed 49.5%, or 192 MW of capacity. The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, will continue to be owned by third parties. TEP is not obligated to purchase any of the third-party owners’ Springerville Unit 1 power. However, TEP is obligated to operate the unit for the third-party owners after the leases expire in January 2015. TEP and the third-party owners have been engaged in discussions regarding the operation of Springerville Unit 1 and related cost sharing arrangements after the expiration of the leases, but have thus far not reached agreement on several key points. If such issues remain unresolved after January 2015, it is difficult to predict what impact this may have on the net cost and operation of Springerville Unit 1.

TEP expects to replace the 195 MW of expiring leased capacity with the purchase of Gila River Unit 3. See Gila River Generating Station Unit 3, below.

Gila River Generating Station Unit 3

In December 2013, TEP and UNS Electric entered into an agreement (the Purchase Agreement) to purchase Gila River Unit 3 for $219 million from a subsidiary of Entegra. The purchase price is subject to adjustments to prorate certain fees and expenses through the closing and in respect of certain operational matters. It is anticipated that TEP will purchase a 75% undivided interest in Gila River Unit 3 (413 MW) for approximately $164 million and UNS Electric will purchase the remaining 25% undivided interest (137 MW) for approximately $55 million, although TEP and UNS Electric may modify the percentage ownership allocation between them. In October 2014, the FERC issued an order authorizing the transaction. We expect the transaction to close in December 2014. The Purchase Agreement remains subject to the completion of certain other agreements associated with the operation of Gila River Unit 3, and other customary closing conditions.

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In June 2014, TEP provided a LOC for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the Purchase Agreement. The seller of Gila River Unit 3 is entitled to draw upon the LOC and apply such amount as liquidated damages if it has validly terminated the Purchase Agreement as a result of misrepresentations by TEP and UNS Electric or the failure of TEP and UNS Electric to close the transaction when the closing conditions have been satisfied. Upon the close of the transaction, the LOC will be canceled. In August 2014, Entegra filed a prepackaged Chapter 11 bankruptcy in the U.S. Bankruptcy Court for the District of Delaware. In September 2014, Entegra's Chapter 11 bankruptcy plan was confirmed. TEP does not expect the bankruptcy to impact the purchase of Gila River Unit 3 and we expect the transaction to close in December 2014.

The purchase of Gila River Unit 3, which would replace the expiring coal-fired leased capacity from Springerville Unit 1 and the expected reduction of coal-fired generating capacity from San Juan Unit 2, is consistent with TEP's strategy to diversify its generation fuel mix. See Note 6.

Springerville Coal Handling Facilities Capital Lease Purchase Commitment

TEP leases interests in the coal handling facilities at the Springerville Generating Station (Springerville Coal Handling Facilities) under two separate lease agreements (Springerville Coal Handling Facilities Leases). The lease agreements have an initial term that expires in April 2015 and provide TEP the option to renew the leases or to purchase the leased interests at the aggregate fixed price of $120 million.

In April 2014, TEP notified the owner participants and their lessors that TEP has elected to purchase their undivided ownership interests in the facilities at the fixed purchase price of $120 million upon the expiration of the lease term in April 2015. Due to TEP’s purchase commitment, TEP recorded, in the second quarter of 2014, an increase to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases on its balance sheets in the amount of $109 million, which represented the present value of the total purchase commitment.

TEP previously agreed with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities Leases were not renewed, TEP would exercise the purchase option under those contracts. Upon TEP’s purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities.

Sales to Mining Customers

Some of TEP's mining customers have indicated they are taking initial steps to increase production either through expansion of their current mining operations or by the re-opening of non-operational mine sites. If efforts to increase production are successful, TEP's mining load could increase over the next several years. The market price for copper and the ability to obtain necessary permits could affect mining industry expansion plans.

In addition to the mining customers that TEP currently serves, the proposed Rosemont Copper Mine near Tucson, Arizona is in the final stages of permitting. The construction and ongoing operations of Rosemont Copper Mine requires electric service from TEP via a 138 kilo-volt (kV) transmission line. In 2012, the ACC approved a Certificate of Environmental Compatibility (CEC) authorizing TEP to build the line to serve the mine. Rosemont Copper Mine will reimburse TEP for the construction of the transmission line. If the Rosemont Copper Mine is constructed and reaches full production, it would be expected to become TEP's largest retail customer, with TEP serving the mine's estimated load of approximately 85 MW.

TEP cannot predict if or when existing mines will expand operations or new or re-opened mines will commence operations.

Springerville Units 3 and 4

TEP receives annual benefits in the form of rental payments and other fees and cost savings from operating Springerville Unit 3 on behalf of Tri-State and Unit 4 on behalf of SRP.

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The table below summarizes the income statement line items in which TEP records revenues and expenses related to Springerville Units 3 and 4:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions of Dollars			
Other Revenues	$26	$27	$71	$73
Fuel Expense	(1)	(2)	(4)	(5)
O&M Expense	(18)	(18)	(49)	(49)
Taxes Other Than Income Taxes	—	—	(1)	(1)

Interest Rates

See Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Fair Value Measurements

See Note 9.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The tables below show TEP's net cash flows after capital expenditures and payments on capital lease obligations, net of payments received on lease debt previously held by TEP:

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Net Cash Flows – Operating Activities (GAAP)	$221	$254
Amounts from Statements of Cash Flows:		
Less: Capital Expenditures	(227)	(180)
Net Cash Flows after Capital Expenditures (Non-GAAP)[1]	(6)	74
Amounts From Statements of Cash Flows:		
Less: Payments of Capital Lease Obligations	(165)	(100)
Plus: Proceeds from Investment in Lease Debt	—	9
Net Cash Flows after Capital Expenditures and Required Payments on Capital Lease Obligations, Net of Payments Received on Lease Debt (Non-GAAP)[1]	$(171)	$(17)

	Nine Months Ended September 30,	
	2014	2013
	Millions of Dollars	
Net Cash Flows – Operating Activities (GAAP)	$221	$254
Net Cash Flows – Investing Activities (GAAP)	(236)	(180)
Net Cash Flows – Financing Activities (GAAP)	18	(119)
Net Increase (Decrease) in Cash	3	(45)
Beginning Cash	25	80
Ending Cash	$28	$35

(1) Net Cash Flows after Capital Expenditures and Net Cash Flows after Capital Expenditures and Required Payments on Capital Lease Obligations, Net of Payments Received on Lease Debt, both non-GAAP measures of liquidity, should not be considered as alternatives to Net Cash Flows—Operating Activities, which is determined in accordance with GAAP. We believe that Net Cash Flows after Capital Expenditures and Net Cash Flows after Capital Expenditures and Required Payments on Capital Lease Obligations, Net of Payments Received on Lease Debt provide useful information as measures of TEP’s ability to fund capital requirements, make required payments on capital lease obligations, and pay dividends to UNS Energy before consideration of financing activities.

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Liquidity Outlook

Cash flows may vary during the year, with cash flow from operations typically the lowest in the first quarter and highest in the third quarter due to TEP’s summer peaking load. As a result of the varied seasonal cash flow, TEP will use, as needed, its revolving credit facility to assist in funding its business activities.

Following completion of the Merger, Fortis made two equity investments in UNS Energy. Fortis contributed $37 million on August 15, 2014 and $200 million on October 10, 2014. UNS Energy contributed $175 million of the investment to TEP on October 10, 2014. This equity investment in TEP will help fund the Gila River Unit 3 and Springerville Unit 1 purchase commitments.

Operating Activities

In the first nine months of 2014, net cash flows from operating activities were $33 million lower than in the same period last year. The decrease was due primarily to: $15 million of merger-related costs; $11 million of increased incentive compensation payments; and an increase of $7 million of capital lease interest paid.

Investing Activities

Net cash flows used for investing activities increased by $57 million in the first nine months of 2014 compared with the same period last year due primarily to a $47 million increase in capital expenditures to fund the construction of new solar projects and maintenance on our generating facilities. Cash flows from investing activities in the first nine months of 2014 also included a $9 million reduction in return of investments in lease debt.

Financing Activities

In the first nine months of 2014, net cash from financing activities was $137 million higher than the same period last year due to: proceeds from the issuance of $150 million of long-term debt; a $35 million increase in borrowings (net of repayments) under the TEP revolving credit facility; and a decrease of $20 million in dividend payments to UNS Energy; partially offset by a $66 million increase in payments of capital lease obligations.

2014 Bond Issuances

In March 2014, TEP issued $150 million of unsecured notes. The bonds bear interest at a fixed rate of 5.0%, mature in March 2044, and may be redeemed at par on or after September 15, 2043. The proceeds of the bond issuance were used to repay approximately $90 million outstanding under TEP's revolving credit facility, while the remaining proceeds were used for general corporate purposes. See Note 4.

Credit Agreement

The TEP Credit Agreement consists of a $200 million revolving credit and LOC facility, and a separate $82 million LOC facility to support tax-exempt bonds. The TEP Credit Agreement expires in November 2016. See Note 4.

TEP provided, in the second quarter of 2014, a LOC for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. TEP's borrowing capacity under the TEP Credit Agreement is reduced by $15 million until the Gila River transaction closes and the LOC is terminated. See Note 6.

At September 30, 2014, there were $35 million of borrowings and there were $16 million of LOCs issued under the revolving credit and LOC facility, leaving $149 million of available borrowing capacity.

As of October 20, 2014, TEP had $185 million available under its revolving credit facility.

The TEP Credit Agreement contains restrictions on mergers and sale of assets. The TEP Credit Agreement also requires TEP not to exceed a maximum leverage ratio. If TEP complies with the terms of the TEP Credit Agreement, TEP may pay dividends to UNS Energy. At September 30, 2014, TEP was in compliance with the terms of the TEP Credit Agreement. See Note 4.

2010 Reimbursement Agreement

In December 2010, TEP entered into a four-year $37 million reimbursement agreement (2010 TEP Reimbursement Agreement). A $37 million LOC was issued pursuant to the 2010 TEP Reimbursement Agreement. The LOC supports $37 million aggregate principal amount of variable rate tax-exempt pollution control bonds that were issued on behalf of TEP in December 2010.

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In February 2014, TEP amended the 2010 TEP Reimbursement Agreement to extend the expiration date of the LOC from 2014 to 2019.
The 2010 TEP Reimbursement Agreement contains substantially the same restrictive covenants as the TEP Credit Agreement described above. At September 30, 2014, TEP was in compliance with the terms of the 2010 TEP Reimbursement Agreement.

Capital Lease Obligations

At September 30, 2014, TEP had $260 million of total capital lease obligations on its balance sheet. The table below provides a summary of the outstanding lease obligations:

Capital Leases	Capital Lease Obligation Balance As Of September 30, 2014 Millions of Dollars	Expiration	Renewal/Purchase Option
Springerville Unit 1[(1)]	$ 61	2015	Fair market value
Springerville Coal Handling Facilities	118	2015	Fixed price purchase option of $120 million[(2)]
Springerville Common Facilities[(3)]	81	2017 and 2021	Fixed price purchase option of $106 million[(3)]
Total Capital Lease Obligations	$ 260		

(1) The Springerville Unit 1 Leases cover both Unit 1 and an undivided one-half interest in certain Springerville Common Facilities. The $61 million balance includes the present value of the lease purchase options agreed to in 2013.

(2) The $118 million balance includes the present value of the lease purchase options elected in April 2014. Upon TEP’s purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. See Factors Affecting Results of Operations, Springerville Coal Handling Facilities Capital Lease Purchase Commitment. Also see Note 4.

(3) The Springerville Common Facilities Leases cover an undivided one-half interest in certain Springerville Common Facilities.

TEP's capital lease obligation balances decline over time due to the normal capital lease payments made by TEP.

Income Tax Position

The 2010 Federal Tax Relief Act and the American Taxpayer Relief Act of 2012 include provisions that make qualified property placed in service between 2010 and 2013 eligible for bonus depreciation for tax purposes. In addition, the IRS issued new guidance related to the treatment of expenditures to maintain, replace, or improve property. These provisions are an acceleration of tax benefits TEP otherwise would have received over 20 years and have created net operating loss carryforwards that can be used to offset future taxable income. As a result, TEP does not expect to pay any federal or state income taxes through 2014. With the approval of the Merger, TEP will be limited in the amount of net operating loss carryforward that can be used annually, which will result in tax payments for 2015.

Contractual Obligations

There have been no changes in TEP's contractual obligations or other commercial commitments from those reported in our 2013 Annual Report on Form 10-K, other than the following changes in 2014:

- In March 2014, TEP issued $150 million of 5.0% unsecured notes due March 2044. See Note 4.
- In April 2014, TEP notified the owner participants and their lessors that TEP has elected to purchase its undivided ownership interests in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million upon the expiration of the lease term in April 2015. Upon TEP's purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million, and Tri-State is obligated to either 1) buy a portion of the facilities for $24 million or 2) continue to make payments to TEP for the use of the facilities. See Note 4.

- TEP entered into new forward purchased power commitments with minimum payment obligations of $18 million million in 2015. See Note 5 .

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- TEP entered into new transportation commitments with minimum payment obligations of $9 million in 2015 and 2016, $10 million in 2017 and 2018, and $42 million in total thereafter through 2040. See Note 5.
- In July 2014, TEP entered into a 20-year PPA with a renewable energy generation facility that achieved commercial operation in July 2014. TEP is obligated to purchase 100% of the output from this facility. TEP expects to make minimum payment obligations under this contract of less than $1 million in years 2015 through 2018 and approximately $4 million in total thereafter. Also, updated estimated annual production amounts increased the minimum payment obligations for existing contracts by $6 million in year 2014, $4 million in years 2015 through 2018, and $56 million in total thereafter.

We have reviewed our contractual obligations and provide the following additional information:

- The TEP Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain pricing based on TEP's credit ratings. A change in TEP's credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments. A downgrade in TEP's credit ratings would not cause a restriction in TEP's ability to borrow under its revolving credit facility.
- The TEP Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain certain financial and other restrictive covenants, including a leverage test. Failure to comply with these covenants would entitle the lenders to accelerate the maturity of all amounts outstanding. At September 30, 2014, TEP was in compliance with these covenants. See TEP Credit Agreement, above.
- TEP conducts its wholesale marketing and risk management activities under certain master agreements whereby TEP may be required to post credit enhancements in the form of cash or an LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, a change in TEP's credit ratings, or if there has been a material change in TEP's creditworthiness. As of September 30, 2014, TEP had posted less than $1 million in LOCs as collateral with wholesale counterparties for credit enhancement.
- In June 2014, TEP provided a LOC for $15 million to the seller of Gila River Unit 3 to satisfy a condition of the purchase agreement. See Note 6.

Dividends on Common Stock

In the first nine months of 2014, TEP did not pay any dividends to UNS Energy. In the first nine months of 2013, TEP paid $20 million in dividends to UNS Energy.

In October 2014, TEP paid $20 million in dividends to UNS Energy.

The approval of the Merger contains a condition restricting subsidiary dividend payments to UNS Energy by TEP to no more than 60 percent of TEP's annual net income for a period of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital (excluding any goodwill recorded) as accounted for in accordance with GAAP. The ratios used to determine the dividend restrictions will be calculated for each calendar year and reported to the ACC annually beginning on April 1, 2016.

CRITICAL ACCOUNTING POLICIES

There have been no significant changes in our accounting policies from those disclosed in our 2013 Annual Report on Form 10-K.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In April 2014, the FASB issued an accounting standards update that limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. This guidance will be effective in the first quarter of 2015. We do not expect the adoption of this guidance to have an impact on the presentation of our financial statements or our disclosures.

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In May 2014, the FASB issued an accounting standards update that will eliminate the transaction- and industry-specific revenue recognition guidance under current U.S. GAAP and replace it with a principles based approach for determining revenue recognition. We will be required to adopt the new guidance retrospectively for annual and interim periods beginning January 1, 2017; early adoption is not permitted. We are evaluating the impact to our financial statements and disclosures.

In August 2014, the FASB issued guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and provide related disclosures. This update is effective for annual and interim periods beginning January 1, 2017; early adoption is permitted. TEP does not expect the adoption of this guidance to have an impact on its disclosures.

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ITEM 3. – QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

TEP’s primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. We enter into interest rate swaps and financing transactions to manage changes in interest rates. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms.

There have been no additional risks and no material changes to market risks disclosed in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2013.

ITEM 4. – CONTROLS AND PROCEDURES

TEP’s Chief Executive Officer and Chief Financial Officer supervised and participated in TEP’s evaluation of its disclosure controls and procedures as such term is defined under Rule 13a – 15(e) or Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this report. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in TEP’s periodic reports filed or submitted under the Exchange Act, is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by TEP in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, or person performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, TEP’s Chief Executive Officer and Chief Financial Officer concluded that TEP’s disclosure controls and procedures are effective.

While TEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting, there has been no change in TEP’s internal control over financial reporting during the third quarter of 2014 that has materially affected, or is reasonably likely to materially affect, TEP’s internal control over financial reporting.

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PART II - OTHER INFORMATION
ITEM 1. – LEGAL PROCEEDINGS
See the legal proceedings described in Item 3. – Legal Proceedings in our 2013 Annual Report on Form 10-K and in Note 5 and in Item 2. – Management’s Discussion and Analysis of Financial Condition and Results of Operations, which descriptions in Note 5 and Item 2 are incorporated herein by reference.

ITEM 1A. – RISK FACTORS
The business and financial results of TEP are subject to numerous risks and uncertainties. You should carefully consider the risks and uncertainties reported in our 2013 Annual Report on Form 10-K. The risk factors below supplement and update the Environmental risk factors described in our 2013 Form 10-K:
Proposed federal regulations to limit greenhouse gas emissions would, if adopted in the form proposed, result in a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.
In June 2014 the EPA proposed carbon emission standards to reduce greenhouse gas emissions from existing power plants. EPA's proposal for Arizona would result in a significant shift in generation from coal to natural gas and renewables and may require that some or all Arizona coal-fired generation plants cease operation by 2020. The EPA is scheduled to finalize those standards by June 2015. These proposed regulations would, if adopted in the form proposed, result in a change in the composition of TEP's generating fleet. As of September 30, 2014, approximately 70% of TEP's generating capacity is fueled by coal. The final rule issued by the EPA could significantly impair the ability to operate certain of TEP's coal-fired generation plants on an economically viable basis or at all. A substantial change in TEP's generation portfolio could result in increased cost of operations and/or additional capital investments. The impact of final regulations to address global climate change will depend on the specific terms of those measures and cannot be determined at this time.
Early closure of TEP's coal-fired generation plants resulting from environmental regulations could result in TEP recognizing material impairments in respect of such plants and increased cost of operations if recovery of our remaining investments in such plants and the costs associated with such early closures were not permitted through rates charged to customers.
TEP's coal-fired generating stations may be required to be closed before the end of their useful lives in response to recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation plants, or coal handling facilities, from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any of such generating stations may force TEP to incur higher costs for replacement capacity and energy. TEP may not be permitted recovery of these costs in the rates it charges its customers.

ITEM 5. – OTHER INFORMATION
SEC REPORTS AVAILABLE ON TEP'S WEBSITE
TEP makes available its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practical after we electronically file or furnish them to the Securities and Exchange Commission (SEC). These reports are available free of charge through TEP’s website address: https://www.tep.com. A link from TEP’s website to these SEC reports is accessible as follows: on TEP's main page, select About Us from the menu shown at the top of the page; next select SEC filings from the menu shown on the About Us page.
UNS Energy’s code of ethics, which applies to the Board of Directors and all officers and employees of UNS Energy and its subsidiaries, and any amendments or any waivers made to the code of ethics, is also available on TEP’s website. TEP is providing the address of TEP’s website solely for the information of investors and does not intend the address to be an active link. Information contained at TEP’s website is not part of any report filed with the SEC by TEP.

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RATIO OF EARNINGS TO FIXED CHARGES

The following table reflects the ratio of earnings to fixed charges for TEP:

	Nine Months Ended September 30, 2014	Twelve Months Ended September 30, 2014
Ratio of Earnings to Fixed Charges	2.856	2.480

For purposes of this computation, earnings are defined as pre-tax earnings plus interest expense and amortization of debt discount and expense. Fixed charges are interest expense, including amortization of debt discount and expense.

ENVIRONMENTAL MATTERS

See Note 5.

Hazardous Air Pollutant Requirements

The Clean Air Act requires the EPA to develop emission limit standards for hazardous air pollutants that reflect the maximum achievable control technology. In February 2012, the EPA issued final rules to set the standards for the control of mercury emissions and other hazardous air pollutants from power plants (MATS rules).

Navajo

Based on the MATS rules, Navajo may require mercury and particulate matter emission control equipment by April 2016. TEP’s share of the estimated capital cost of this equipment is less than $1 million for mercury control and about $43 million if the installation of baghouses to control particulates is necessary. The operator of Navajo is currently analyzing the need for baghouses under various regulatory scenarios, including the recently finalized Best Available Retrofit Technology (BART) rule(see Regional Haze Rules below). TEP expects its share of the annual operating costs for mercury control and baghouses to be less than $1 million each.

San Juan

TEP expects San Juan’s current emission controls to be adequate to comply with the MATS rules.

Four Corners

A study determined that Four Corners' emission controls are adequate with some compliance margin. TEP expects Four Corner’s current emission controls to be adequate to comply with the MATS rules.

Springerville Generating Station

Based on the MATS rules, Springerville Generating Station (Springerville) may require mercury emission control equipment by April 2016. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $1 million. Estimated costs are split equally between the two units. TEP will own 49.5% of Springerville Unit 1 upon close of the lease option purchases in January 2015; after the completion of such purchases, third party owners will be responsible for 50.5% of environmental costs attributed to Springerville Unit 1. TEP will continue to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

Sundt Generating Station

TEP expects the MATS rules will have little effect on capital expenditures at Sundt.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as BART for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rules call for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. BART applies to plants built between August 1962 and August 1977. Because Navajo and Four Corners are located on the Navajo Indian Reservation, they are not subject to state oversight; the EPA oversees regional haze planning for these power plants.

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Complying with the EPA’s BART findings, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in the units they own at these power plants. TEP cannot predict the ultimate outcome of these matters.

Navajo

In January 2013, the EPA proposed a BART determination that would require the installation of Selective Catalytic Reduction (SCR) technology on all three units at Navajo by 2023. In July 2013, SRP, along with other stakeholders including impacted government agencies, environmental organizations, and tribal representatives, submitted an agreement to the EPA that would achieve greater NOx emission reductions than the EPA's proposed BART rule. In September 2013, the EPA issued a supplemental proposal incorporating the provisions of the agreement as a better-than-BART alternative. In August 2014, the EPA published the final Regional Haze FIP for Navajo with BART requirements consistent with the better-than-BART alternative as presented in the proposal. The final BART includes options that accommodate potential ownership changes at the plant. The plant as until December 2019 to notify the EPA which option will be implemented.

Among other things, the FIP calls for the shut-down of one unit or an equivalent reduction in emissions by 2020. The shutdown of one unit will not impact the total amount of energy delivered to TEP from Navajo. Additionally, the remaining Navajo participants would be required to install SCR or an equivalent technology on the remaining two units by 2030, and the current owners have to cease their operation of conventional coal-fired generation at Navajo no later than December 22, 2044. The Navajo Nation can continue operation after 2044 at its election.

If SCR technology is ultimately implemented at Navajo, TEP estimates its share of the capital cost will be $42 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouses would be about $43 million. TEP's share of annual operating costs for SCR and baghouses is estimated at less than $1 million each.

San Juan

In August 2011, the EPA issued a Federal Implementation Plan (FIP) establishing new emission limits for air pollutants at San Juan. These requirements were more stringent than those proposed by the State of New Mexico. The FIP required the installation of SCR technology with sorbent injection on all four units to reduce NOx and control sulfuric acid emissions by September 2016.

In 2011, PNM filed a petition for review of, and a motion to stay, the FIP with the United States Court of Appeals for the Tenth Circuit (Tenth Circuit). In addition, the operator filed a request for reconsideration of the rule with the EPA and a request to stay the effectiveness of the rule pending the EPA's reconsideration and review by the Tenth Circuit. The State of New Mexico filed similar motions with the Tenth Circuit and the EPA. Several environmental groups were granted permission to join in opposition to PNM's petition to review in the Tenth Circuit. In addition, WildEarth Guardians filed a separate appeal against the EPA challenging the FIP's five-year implementation schedule. PNM was granted permission to join in opposition to that appeal. In March 2012, the Tenth Circuit denied PNM's and the State of New Mexico's motion for stay. Oral argument on the appeal was heard in October 2012.

In February 2013, the State of New Mexico, the EPA, and PNM signed a non-binding agreement (Settlement Agreement) that outlines an alternative to the FIP. The terms of the Settlement Agreement include: the retirement of San Juan Units 2 and 3 by December 31, 2017; the replacement by PNM of those units with non-coal generation sources; and the installation of SNCR on San Juan Units 1 and 4 by January 2016 or later depending on the timing of the EPA approvals. The New Mexico Environmental Department (NMED) prepared a revision to the regional haze State Implementation Plan (SIP) incorporating the provisions of the Settlement Agreement, and in September 2013, the New Mexico Environmental Improvement Board approved the SIP revision. In May 2014, the EPA proposed to approve the revised SIP and withdraw the existing FIP.

In October 2014, the EPA published a final rule approving the revised SIP covering BART requirements for San Juan. Subsequent to that action, the EPA withdrew the FIP addressing the same requirements. TEP estimates its share of the cost to install SNCR technology on San Juan Unit 1 would be approximately $35 million. TEP's share of incremental annual operating costs for SNCR is estimated at $1 million. TEP owns 340 MW, or 50%, of San Juan Units 1 and 2. If

San Juan Unit 2 is retired, TEP's coal-fired generating capacity would be reduced by 170 MW.

In connection with the implementation of the SIP revision and the retirement of San Juan Units 2 and 3, some of the San Juan owner participants (Participants) have expressed a desire to exit their ownership in the plant. As a result, the Participants are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting Participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The Participants have engaged a mediator to assist in facilitating the resolution of these matters among the owners.

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The owners of the affected units also may seek approvals of their utility commissions or governing boards. We are unable to predict the outcome of the negotiations and mediation.

In October 2013, the Tenth Circuit ruled on a motion filed by PNM for abatement of the pending petitions for review and seeking deferral of briefing on a simultaneously-filed motion to stay the FIP. The Tenth Circuit placed the pending petitions for review in abeyance and set a schedule for the parties to file status reports. The court ruled that, if at any time the Settlement Agreement is not implemented as contemplated, any party to the litigation may file a motion seeking to lift the abatement.

At September 30, 2014, the book value of TEP's share of San Juan Unit 2 was $111 million. If Unit 2 is retired early, we expect to request ACC approval to recover all costs associated with the early closure of the unit. TEP cannot predict the ultimate outcome of this matter.

Four Corners

In 2012, the EPA finalized the regional haze FIP for Four Corners. The final FIP requires SCR technology to be installed on one unit by October 2016 and the remaining units by October 2017. In December 2013, APS (the operator) decided to shut down Units 1, 2, and 3 and install SCRs on Units 4 and 5. Under this scenario, the installation of SCR technology can be delayed until July 2018. TEP's estimated share of the capital costs to install SCR technology on Units 4 and 5 is approximately $35 million. TEP's share of incremental annual operating costs for SCR is estimated at $2 million.

Springerville

The BART provisions of the Regional Haze Rules requiring emission control upgrades do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s which is after the time frame as designated by the rules. Other provisions of the Regional Haze Rules requiring further emission reduction are not likely to impact Springerville operations until after 2018.

Sundt

In July 2013, the EPA rejected the Arizona state implementation plan determination that Sundt Unit 4 is not subject to the BART provisions of the Regional Haze Rule and developed a time-line to issue a federal implementation plan for emissions sources including Sundt Unit 4. While TEP does not agree that Sundt Unit 4 is subject to BART, it submitted a better-than-BART proposal in November 2013 which called for the elimination of coal as a fuel source at Sundt by the end of 2017. In June 2014, the EPA issued a final BART rule that would require TEP to either (i) install, by mid-2017, SNCR and dry sorbent injection (DSI) if Sundt Unit 4 continues to use coal as a fuel source, or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. TEP estimates that the cost to install SNCR and DSI would be approximately $12 million, and the incremental annual operating costs would be $5 million to $6 million. Under the rule, TEP is required to notify the EPA of its decision by March 2017.

At September 30, 2014, the net book value of the Sundt coal handling facilities was $17 million. If the coal handling facilities are retired early, we expect to request ACC approval to recover all the remaining costs of the coal handling facilities.

Greenhouse Gas Regulation

In June 2013, President Obama directed the EPA to move forward with carbon emission regulations for both new and existing fossil-fueled power plants.

In January 2014, the EPA published a re-proposed rule for new power plants. TEP does not anticipate that a final rule related to new fossil-fueled power plant sources will have a significant impact on operations.

In June 2014, the EPA issued proposed carbon emission regulations for existing power plants called the Clean Power Plan. The Clean Power Plan targets a nation-wide reduction in carbon emissions of 30% by 2030. To achieve this goal, the proposed plan sets carbon emission rates for each state that must be achieved by an interim period of 2020-2029, with final rates by 2030. States can apply a variety of strategies to achieve the interim and final emission rates. Using 2012 as a baseline year, Arizona's carbon emission rate for 2030 represents a 52% reduction. The EPA expects to issue a final rule by June 2015, and under the current proposal, states must file implementation plans by June 2016 (or June 2017 for multi-state plans, with a possible one-year extension). In October 2014, the EPA issued a supplemental proposal regarding carbon emissions regulation impacting the Navajo Nation and the Four Corners and Navajo Generating Stations. The regulation if implemented as proposed will require carbon reductions on the Navajo

Reservation. TEP is working with the plant operators to determine the impact to operations. TEP cannot estimate the impact of the new proposed rule on its operations at this time.

TEP will continue working with federal and state regulatory authorities, other neighboring utilities, and stakeholders to seek relief from the proposed standard by reducing the disproportionately high level of carbon emissions reduction for Arizona, and to seek relief from the 2020 and 2030 proposed compliance requirements. Comments on the proposed rule were originally due

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October 16, 2014, however, the EPA has extended the comment deadline to December 1, 2014. The proposed rule has been challenged in court and is subject to further legal challenge. TEP cannot predict the ultimate outcome of these matters.

Coal Combustion Residuals Regulations

The EPA is developing regulations for Coal Combustion Residuals (CCR) placed in landfills and surface impoundments (i.e. ponds).

In June 2010, the EPA issued a proposed rule presenting for public comment two approaches for regulating CCR: 1) as solid waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA); and 2) as hazardous waste under Subtitle C of RCRA. Both approaches would maintain an exception from regulation for beneficial use. In May 2014, the EPA entered a consent decree agreeing to take final action on the proposed rule as it relates to regulation under Subtitle D of RCRA by December 2014.

If the final rule is structured similar to existing “municipal solid waste” rules, TEP’s ash disposal facility at Springerville would likely be in compliance with the requirements, however, upgrades could be required for future disposal. At Navajo and Four Corners, the ash that cannot be sold is land filled on site. These sites also could be required to upgrade. At San Juan, the ash that cannot be sold is returned to the mine. The proposed rule would not address mine placement of CCRs. Mine placement will be addressed through a separate rule-making under the oversight of the Department of Interior's Office of Surface Mining Reclamation and Enforcement.

If the final rule regulates CCR as a “hazardous waste”, in addition to the disposal facility upgrades discussed above, upgrades to handling and storage facilities at the plant sites would also be required.

TEP cannot determine the economic impact of this rule at this time.

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ITEM 6. – EXHIBITS

See Exhibit Index.

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.

TUCSON ELECTRIC POWER COMPANY
(Registrant)

Date:	November 7, 2014	/s/ Kevin P. Larson Kevin P. Larson Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

12	—	Computation of Ratio of Earnings to Fixed Charges .
31(a)	—	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by David G. Hutchens.
31(b)	—	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by Kevin P. Larson.
*32	—	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101.INS	—	XBRL Instance Document
101.SCH	—	XBRL Taxonomy Extension Schema Document
101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	—	XBRL Taxonomy Extension Definition Linkbase Document

* Pursuant to Item 601(b)(32)(ii) of Regulation S-K, this certificate is not being "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.