TUCSON ELECTRIC POWER CO
Form 10-Q
November 06, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015
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	86-0062700
(State or other jurisdiction of incorporation or organization)	(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
(Former name, former address and former fiscal year, if changed since last report): N/A

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
All shares of outstanding common stock of Tucson Electric Power Company are held by its parent company, UNS Energy Corporation, which is an indirect, wholly owned subsidiary of Fortis Inc. There were 32,139,434 shares of common stock, no par value, outstanding as of November 5, 2015.

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DEFINITIONS

The abbreviations and acronyms used in the third quarter 2015 Form 10-Q are defined below:

2010 Credit Agreement	The 2010 Credit Agreement consisted of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds. In October 2015, TEP terminated the 2010 Credit Agreement and replaced it with the 2015 Credit Agreement
2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
2014 Credit Agreement	The 2014 Credit Agreement consisted of a $70 million revolving credit commitment and a $130 million term loan commitment portion. The term loan was terminated upon repayment in April 2015. The revolver credit portion was also terminated after repayment.
2015 Credit Agreement	The 2015 Credit Agreement provides for a $250 million revolving credit and LOC facility
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 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 power costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
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
EE	Energy Efficiency
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
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	Kilovolt(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter(s) 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
PNM	Public Service Company of New Mexico
ppb	Parts per billion
PPFAC	Purchased Power and Fuel Adjustment Clause
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas

RES	Renewable Energy Standard
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SES	Southwest Energy Solutions, Inc.
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
Springerville Coal Handling Facilities	Coal handling facilities at Springerville used in common by all four Springerville units
Springerville Coal Handling Facilities Leases	Leases previously in place 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 Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangements that were previously in place 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
Third-Party Owners	Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1)
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. Tucson Electric Power Company (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, intentions, expectations, objectives, goals, strategies, future events, projections 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, believes, 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, except as otherwise may be required by the federal securities laws.

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 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 I, Item 1A of our 2014 Form 10-K; 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; changes in energy consumption by retail customers; 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; the inability to make additions to our existing high voltage transmission system; 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; ability to obtain coal from our suppliers; cyber attacks or challenges to our information security; and the performance of TEP's generating plants.

PART I
ITEM 1. FINANCIAL STATEMENTS
TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME (Unaudited)
(Amounts in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Operating Revenues				
Electric Retail Sales	$337,284	$316,387	$803,204	$760,192
Electric Wholesale Sales	40,545	37,053	129,681	111,692
Other Revenues	30,915	33,971	89,427	92,658
Total Operating Revenues	408,744	387,411	1,022,312	964,542
Operating Expenses				
Fuel	91,853	89,199	239,489	225,163
Purchased Power	40,378	49,902	107,785	125,423
Transmission and Other PPFAC Recoverable Costs	7,386	5,222	18,966	12,683
Increase (Decrease) to Reflect PPFAC Recovery Treatment	9,846	(5,376)	20,627	(20,167)
Total Fuel and Purchased Power	149,463	138,947	386,867	343,102
Operations and Maintenance	88,155	112,667	256,455	273,784
Depreciation	34,395	31,966	103,347	93,857
Amortization	4,342	6,973	14,523	21,449
Taxes Other Than Income Taxes	12,038	11,960	38,184	35,800
Total Operating Expenses	288,393	302,513	799,376	767,992
Operating Income	120,351	84,898	222,936	196,550
Other Income (Deductions)				
Interest Income	26	7	77	181
Other Income	2,408	2,024	4,466	6,123
Other Expense	(983)	(7,170)	(2,101)	(11,979)
Appreciation (Depreciation) in Value of Investments	(1,277)	(504)	(1,036)	375
Total Other Income (Deductions)	174	(5,643)	1,406	(5,300)
Interest Expense				
Long-Term Debt	15,630	15,579	45,746	45,326
Capital Leases	991	1,202	3,003	9,048
Other Interest Expense	125	104	989	557
Interest Capitalized	(781)	(850)	(1,977)	(2,878)
Total Interest Expense	15,965	16,035	47,761	52,053
Income Before Income Taxes	104,560	63,220	176,581	139,197
Income Tax Expense	36,021	23,576	60,787	51,656
Net Income	$68,539	$39,644	$115,794	$87,541

The accompanying notes are an integral part of these financial statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)
(Amounts in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Comprehensive Income				
Net Income	$68,539	$39,644	$115,794	$87,541
Other Comprehensive Income (Loss)				
Net Changes in Fair Value of Cash Flow Hedges:				
Net of Income Tax (Expense) Benefit of ($289) and ($450)	452	697		
Net of Income Tax (Expense) Benefit of ($583) and ($1,117)			908	1,672
Supplemental Executive Retirement Plan Adjustments:				
Net of Income Tax (Expense) Benefit of ($38) and ($16)	60	25		
Net of Income Tax (Expense) Benefit of ($113) and ($46)			181	74
Total Other Comprehensive Income (Loss), Net of Tax	512	722	1,089	1,746
Total Comprehensive Income	$69,051	$40,366	$116,883	$89,287

The accompanying notes are an integral part of these financial statements.

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in thousands)

	Nine Months Ended September 30, 2015	2014
Cash Flows from Operating Activities		
Net Income	$115,794	$87,541
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation Expense	103,347	93,857
Amortization Expense	14,523	21,449
Amortization of Deferred Debt-Related Costs included in Interest Expense	2,288	1,959
Provision for Springerville Unit 1 - Third-Party Owners Unrealized Revenue	16,867	—
Use of Renewable Energy Credits for Compliance	16,139	15,129
Deferred Income Taxes	61,083	51,544
Pension and Retiree Expense	13,941	10,236
Pension and Retiree Funding	(28,922)	(12,989)
Share-Based Compensation Expense	862	5,010
Allowance for Equity Funds Used During Construction	(3,391)	(4,983)
LFCR and DSM Revenues	(11,858)	(9,960)
Increase (Decrease) to Reflect PPFAC Recovery	20,627	(20,167)
Fortis Acquisition Direct Customer Benefit	—	18,870
Changes in Current Assets and Current Liabilities:		
Accounts Receivable	(64,439)	(45,758)
Materials, Supplies, and Fuel Inventory	(7,450)	(274)
Accounts Payable	(5,739)	(472)
Interest Accrued	(3,687)	(3,849)
Taxes Other Than Income Taxes	18,574	18,745
Other, net	7,510	(4,620)
Net Cash Flows – Operating Activities	266,069	221,268
Cash Flows from Investing Activities		
Capital Expenditures	(259,638)	(227,153)
Purchase of Intangibles—Renewable Energy Credits	(22,672)	(22,047)
Purchase of Springerville Unit 1 Lease Assets	(45,753)	—
Purchase of Springerville Coal Handling Facilities Lease Assets	(120,312)	—
Proceeds from Sale of Springerville Coal Handling Facilities	23,656	—
Contributions in Aid of Construction	5,761	10,623
Other, net	—	2,260
Net Cash Flows—Investing Activities	(418,958)	(236,317)
Cash Flows from Financing Activities		
Proceeds from Borrowings Under Revolving Credit Facility	148,000	190,000
Repayments of Borrowings Under Revolving Credit Facility	(233,000)	(155,000)
Proceeds from Borrowings Under Term Loan	130,000	—
Repayments of Borrowings Under Term Loan	(130,000)	—
Proceeds from Issuance of Long-Term Debt	299,019	149,168
Repayments of Long-Term Debt	(208,600)	—
Dividend Paid	(25,000)	—
Payments of Capital Lease Obligations	(13,464)	(165,145)
Payment of Debt Issue/Retirement Costs	(2,987)	(1,652)

Contribution from Parent	180,000	—
Other, net	1,659	551
Net Cash Flows—Financing Activities	145,627	17,922
Net Increase (Decrease) in Cash and Cash Equivalents	(7,262)	2,873
Cash and Cash Equivalents, Beginning of Period	74,170	25,335
Cash and Cash Equivalents, End of Period	$66,908	$28,208

The accompanying notes are an integral part of these financial statements.

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TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in thousands)

	September 30, 2015	December 31, 2014
ASSETS		
Utility Plant		
Plant in Service	$5,457,972	$5,175,148
Utility Plant Under Capital Leases	131,705	667,157
Construction Work in Progress	186,279	109,070
Total Utility Plant	5,775,956	5,951,375
Less Accumulated Depreciation and Amortization	(2,174,146)	(2,052,216)
Less Accumulated Amortization of Capital Lease Assets	(98,527)	(473,969)
Total Utility Plant—Net	3,503,283	3,425,190
Investments and Other Property	36,924	37,599
Current Assets		
Cash and Cash Equivalents	66,908	74,170
Accounts Receivable—Customer	110,886	78,061
Accounts Receivable—Other	34,898	16,437
Accounts Receivable—Due from Affiliates	5,322	5,382
Unbilled Accounts Receivable	49,976	36,804
Allowance for Doubtful Accounts—Customer	(4,904)	(4,885)
Allowance for Doubtful Accounts—Other	(16,867)	—
Fuel Inventory	29,977	36,368
Materials and Supplies	96,035	86,750
Regulatory Assets	50,831	69,383
Deferred Income Taxes	50,168	102,006
Derivative Instruments	3,104	1,633
Assets Held for Sale	21,550	—
Other	26,299	21,871
Total Current Assets	524,183	523,980
Regulatory and Other Assets		
Regulatory Assets	221,012	223,192
Derivative Instruments	59	300
Other	25,327	22,161
Total Regulatory and Other Assets	246,398	245,653
Total Assets	$4,310,788	$4,232,422

The accompanying notes are an integral part of these financial statements.

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in thousands)

	September 30, 2015	December 31, 2014
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$1,487,662	$1,215,779
Capital Lease Obligations	54,597	69,438
Long-Term Debt	1,463,026	1,372,414
Total Capitalization	3,005,285	2,657,631
Current Liabilities		
Current Obligations Under Capital Leases	13,827	173,822
Borrowings Under Revolving Credit Facilities	—	85,000
Accounts Payable—Trade	91,198	110,480
Accounts Payable—Due to Affiliates	3,755	2,933
Accrued Taxes Other than Income Taxes	54,684	36,110
Accrued Employee Expenses	25,958	15,679
Accrued Interest	12,660	21,021
Regulatory Liabilities	36,435	38,847
Customer Deposits	19,924	20,339
Derivative Instruments	10,864	18,874
Other	7,170	9,673
Total Current Liabilities	276,475	532,778
Regulatory and Other Liabilities		
Deferred Income Taxes	509,680	491,546
Regulatory Liabilities	308,427	321,186
Pension and Other Postretirement Benefits	118,065	138,319
Derivative Instruments	4,561	6,288
Other	88,295	84,674
Total Regulatory and Other Liabilities	1,029,028	1,042,013
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,310,788	$4,232,422

The accompanying notes are an integral part of these financial statements.

(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDER'S EQUITY (Unaudited)
(Amounts in thousands)

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
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 Tax				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
	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances at December 31, 2014	$1,116,539	$(6,357)	$111,523	$ (5,926)	$1,215,779
Net Income			115,794		115,794
Other Comprehensive Income, Net of Tax				1,089	1,089
Dividend Declared			(25,000)		(25,000)
Contribution from Parent	180,000				180,000
Balances at September 30, 2015	$1,296,539	$(6,357)	$202,317	$ (4,837)	$1,487,662

The accompanying notes are an integral part of these financial statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

TEP is a regulated utility that generates, transmits, and distributes electricity to approximately 417,000 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. 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.

BASIS OF PRESENTATION

We prepared our condensed consolidated financial statements according to generally accepted accounting principles in the United States of America (GAAP), including specific accounting guidance for regulated operations, and the Securities and Exchange Commission's (SEC) interim reporting requirements. The condensed consolidated financial statements include the accounts of TEP and its subsidiaries. In the consolidation process, accounts of the parent and subsidiaries are combined and intercompany balances and transactions are eliminated. TEP jointly owns several generating stations and transmission facilities with both affiliated and non-affiliated entities. TEP's proportionate share of jointly owned facilities is recorded as Utility Plant on the Condensed Consolidated Balance Sheets, and our proportionate share of the operating costs associated with these facilities is included in the Condensed Consolidated Statements of Income. These condensed consolidated financial statements exclude some information and footnotes required by GAAP and the SEC for annual financial statement reporting and should be read in conjunction with the consolidated financial statements and footnotes in our 2014 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. Certain amounts from prior periods have been reclassified to conform to the current period presentation.

FORTIS ACQUISITION OF UNS ENERGY

As disclosed in our 2014 Annual Report on Form 10-K, Fortis completed the acquisition of UNS Energy in August 2014. TEP recorded $14 million and $15 million in the three and nine months ended September 30, 2014 as its allocated share of merger-related expenses. Merger-related expenses include investment banker fees, legal expenses, and accelerated expenses for certain share-based compensation awards and were included in Operations and Maintenance in the Condensed Consolidated Statements of Income. In addition, TEP agreed to provide credits on retail customers' bills as a result of the Fortis acquisition. TEP recorded $19 million in the three and nine months ended September 30, 2014 related to customer bill credits which were included in Operations and Maintenance in the Condensed Consolidated Statements of Income.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2015, we adopted accounting guidance that limits the circumstances under which a disposal may be reported as a discontinued operation and requires new disclosures. The adoption of this guidance did not have any impact on our disclosures, financial condition, results of operations, or cash flows as we did not have any activities that required application of this accounting guidance.

NOTE 2. REGULATORY MATTERS

The Arizona Corporation Commission (ACC) and the Federal Energy Regulatory Commission (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.

2015 RATE CASE

On November 5, 2015, TEP filed a general rate case with the ACC based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

The key provisions of TEP's general rate case include:

- a Base Rate increase of $110 million, or 12.0%, compared with adjusted test year revenues;

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- a 7.34% return on original cost rate base of $2.1 billion, which includes approximately $73 million of post-test year adjustments for utility plant that is expected to be in service by December 31, 2016;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of San Juan Unit 2 and the Sundt Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Springerville Unit 1 that is available to TEP for dispatch to serve retail customer needs and to recover the related operating costs through the Fuel and Purchased Power Adjustor Clause (“PPFAC”); and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

TEP cannot predict the outcome of this proceeding or whether its rate request will be adopted by the ACC in whole or in part.

COST RECOVERY MECHANISMS

Purchased Power and Fuel Adjustment Clause

The ACC adjusts TEP's PPFAC rate annually each April 1 for the subsequent 12-month period. The PPFAC rates during the periods reported were as follows:

Period	Cents per kWh
April 2015 through March 2016	0.68
October 2014 through March 2015 (1)	0.50
May 2014 through September 2014 (1)	0.10
July 2013 through April 2014 (2)	(0.14)

(1) The ACC approved a two-step increase to shift a higher level of recovery into the winter season.
(2) The effective date of the 2012 PPFAC rate reduction was deferred to coincide with the effective date of the 2013 Rate Order.

In September 2011, a fire at the underground mine providing coal to the San Juan Generating Station (San Juan) caused interruptions to mining operations and resulted in increased fuel costs. The 2013 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 (SJCC) and distribution of insurance proceeds to San Juan participants. Beginning March 2014 through September 30, 2015, TEP received a total of $9 million in insurance proceeds. For the nine months ended September 30, 2015 and 2014, TEP received insurance proceeds of $1 million and $8 million, respectively. The insurance proceeds offset the deferred fuel costs and are included in our statement of cash flows as an operating activity. In October 2015, the final insurance payment was received. The remaining $1 million of unreimbursed fuel costs will be recovered through TEP's PPFAC, in accordance with the 2013 Rate Order.

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 an annual performance incentive. TEP records its annual DSM performance incentive in the first quarter of each year, with $3 million recorded in 2015 and $2 million in 2014 related to performance in each respective prior calendar year. This performance incentive is included in Electric Retail Sales in the Condensed Consolidated Statements of Income.

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 kilowatt-hours (kWh) sales as a result of implementing ACC-approved EE programs and Distributed Generation (DG) targets. TEP records a regulatory asset and recognizes LFCR revenues when the amounts are verifiable regardless of when the lost retail kWh sales occur. For recovery of the LFCR regulatory asset, TEP is required to file an annual LFCR adjustment request with the ACC for the LFCR revenues recognized in the prior year.

The recovery is subject to a year-over-year cap of 1% of TEP's total retail revenues.

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TEP recorded a regulatory asset and recognized LFCR revenues of $3 million and $9 million in the three and nine months ended September 30, 2015. TEP recorded $2 million and $8 million in the three and nine months ended September 30, 2014. LFCR revenues are included in Electric Retail Sales in the Condensed Consolidated Statements of Income.

REGULATORY ASSETS

Upon expiration of the Springerville Generating Station Unit 1 (Springerville Unit 1) capital leases in January 2015, TEP recorded a regulatory asset of $25 million for unamortized leasehold improvement costs that relate to third-party ownership interests. These leasehold improvements, previously recorded in Plant in Service on the balance sheet, represent investments TEP made through the end of the lease term to ensure that the Springerville Unit 1 facilities continued providing safe, reliable service to TEP's customers. In the 2013 Rate Order, TEP received ACC authorization to recover these costs over a 10-year amortization period for leasehold improvements at Springerville Unit 1. TEP owns a 49.5% undivided interest in Springerville Unit 1.

NOTE 3. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with Fortis, UNS Energy and its affiliated subsidiaries including UniSource Energy Services, Inc., UNS Electric, Inc. (UNS Electric), UNS Gas, Inc. (UNS Gas), and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy Affiliates). These transactions include the sale and purchase of power, common cost allocations, and the provision of corporate and other labor related services.

The following table summarizes related party balances included in the Condensed Consolidated Balance Sheets:

(in millions)	September 30, 2015	December 31, 2014
Receivables from Related Parties		
UNS Electric	$4	$4
UNS Gas	1	1
Total Due from Related Parties	$5	$5
Payables to Related Parties		
SES	$3	$2
UNS Energy	1	—
UNS Electric	—	1
Total Due to Related Parties	$4	$3

The following table summarizes related party transactions included in the Condensed Consolidated Statements of Income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Wholesale Sales - TEP to UNS Electric (1)	$2	$2	$5	$3
Wholesale Sales - UNS Electric to TEP (1)	—	2	1	3
Control Area Services - TEP to UNS Electric (2)	1	1	1	2
Common Costs - TEP to UNS Energy Affiliates (3)	3	3	9	10
Supplemental Workforce - SES to TEP (4)	4	4	13	12
Corporate Services - UNS Energy to TEP (5)	1	11	3	13
Corporate Services - UNS Energy Affiliates to TEP (6)	—	—	1	1

(1) TEP sells and purchases power with UNS Electric at prevailing market prices.

(2) TEP charges UNS Electric for control area services under a FERC-approved Control Area Services Agreement.

(3) Common costs (information systems, facilities, etc.) are allocated on a cost-causative basis and recorded as revenue by TEP. The method of allocation is deemed reasonable by management and is reviewed by the ACC as part of the rate case process.

(4) SES provides supplemental workforce and meter-reading services to TEP based on related party service agreements. The charges are based on costs of services performed and deemed reasonable by management.

(5) Costs for corporate services at UNS Energy, such as Fortis management fees, legal fees, and audit fees, are allocated to its subsidiaries using the Massachusetts Formula, an industry accepted method of allocating common costs to affiliated entities. TEP's allocation is approximately 81% of UNS Energy's allocated costs. For the three and nine months ended September 30, 2015, these costs included approximately $1 million and $3 million, respectively, in Fortis management fees. For the three and nine months ended September 30, 2014, these costs included approximately $11 million and $12 million, respectively, in merger related costs (excluding TEP allocated labor related charges).

(6) Costs for corporate services (finance, accounting, tax, legal, and information technology) and other labor services for UNS Energy Affiliates are directly assigned to the benefiting entity at a fully burdened cost when possible.

SHARE-BASED COMPENSATION EXPENSE

In January 2015, UNS Energy established a new share-based compensation plan, the 2015 Share Unit Plan (the Plan), to promote greater alignment of interests with the senior management of UNS Energy and its subsidiaries, UNS Energy's customers, and the shareholders of Fortis. TEP's allocated share-based compensation expense under the Plan for the three and nine months ended September 30, 2015 was less than $1 million and $1 million, respectively.

With the completion of the Fortis acquisition of UNS Energy in August 2014, TEP recognized accelerated vesting of all outstanding non-vested UNS Energy share based awards that otherwise would have been recognized over the remaining vesting periods through February 2017. For the three and nine months ended September 30, 2014, TEP recognized $4 million and $5 million of expense under UNS Energy's prior share-based compensation plans.

CONTRIBUTION FROM PARENT

In June 2015, UNS Energy made an equity contribution to TEP of $180 million. TEP used proceeds from the equity contribution to repay the outstanding balances under TEP's revolving credit facilities. The remaining balance of the proceeds was used to redeem bonds in August 2015 and to provide additional liquidity to TEP. See Note 4 for additional information regarding the August 2015 bond redemption.

DIVIDEND PAID

TEP paid a $25 million dividend to UNS Energy in the first nine months of 2015 and no dividend in the first nine months of 2014.

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 2014 Annual Report on Form 10-K.

CAPITAL LEASE OBLIGATIONS

Springerville Unit 1 Capital Lease Purchase

In January 2015, upon expiration of the lease term, TEP purchased leased interests comprising 24.8% of Springerville Unit 1, representing 96 megawatts (MW) of capacity, for an aggregate purchase price of $46 million, the appraised value. With the completion of the purchase, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity. Furthermore, TEP is obligated to operate the unit for the Third-Party Owners under existing agreements. The Third-Party Owners are obligated to compensate TEP for their pro rata share of expenses. See Note 5 for additional information regarding the Third-Party Owners.

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon the expiration of the lease, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million, bringing its total ownership of the assets to 100%.

In May 2015, Salt River Project Agricultural Improvement and Power District (SRP), the owner of Springerville Unit 4, purchased from TEP a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million.

Tri-State Generation and Transmission Association, Inc. (Tri-State), the lessee of Springerville Unit 3, is obligated to either: 1) buy a 17.05% undivided interest in the facilities for approximately $24 million; or 2) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option. At September 30, 2015, Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities is classified as Assets Held for Sale on the Condensed Consolidated Balance Sheets.

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DEBT ISSUANCES AND REDEMPTIONS

In January 2015, amounts borrowed under the term loan portion of the 2014 Credit Agreement were used to purchase $130 million aggregate principal amount of unsecured Industrial Development Revenue Bonds issued in June 2008 by the Industrial Development Authority (IDA) of Pima County for the benefit of TEP. The multi-modal bonds mature in September 2029. At September 30, 2015, TEP had not canceled or remarketed the repurchased bonds and as a result the bonds were not recorded in Long-Term Debt on the Condensed Consolidated Balance Sheets.

In February 2015, TEP issued and sold $300 million aggregate principal amount of senior unsecured notes bearing interest at a fixed rate of 3.05% and maturing March 15, 2025. In March 2015, TEP used the net proceeds from the sale to repay $215 million on outstanding borrowings under its credit agreements. In April 2015, the remaining net proceeds were used to pay a portion of the purchase price for its ownership interests in the Springerville Coal Handling Facilities. TEP may redeem the notes prior to December 15, 2024, with a make-whole premium plus accrued interest. On or after December 15, 2024, TEP may redeem the notes at par plus accrued interest. Interest on the notes is payable semi-annually, beginning September 15, 2015, and ending at maturity.

In June 2015, TEP issued irrevocable redemption notices for two series of variable rate tax-exempt bonds with an aggregate principal amount of $79 million. These two series of local-furnishing bonds, issued in 1982 by the IDA of Pima County for the benefit of TEP, were backed by Letters of Credit (LOCs) issued under TEP’s 2010 Credit Agreement. In August 2015, the bonds were redeemed prior to maturity at par and the associated LOCs were terminated in September 2015. At September 30, 2015, no remaining balance for the bonds is reflected on the Condensed Consolidated Balance Sheets.

CREDIT AGREEMENTS

2015 Credit Agreement

In October 2015, TEP entered into an unsecured credit agreement (2015 Credit Agreement) replacing the 2010 Credit Agreement. The 2015 Credit Agreement provides for a $250 million revolving credit and LOC facility. The LOC sublimit is $50 million. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. All amounts outstanding under the facility will be due in October 2020, the termination date of the credit agreement. The agreement allows for two one year extensions of the facility if certain conditions are satisfied.

Interest rates and fees under the 2015 Credit Agreement are based on a pricing grid tied to TEP’s credit ratings. The interest rate currently in effect on borrowings is London Interbank Offered Rate (LIBOR) plus 1.00% for Eurodollar loans or Alternate Base Rate with no spread for Alternate Base Rate loans.

As of November 5, 2015, there was $250 million available under the 2015 Credit Agreement's revolving credit and LOC facilities.

2014 Credit Agreement

In March 2015, net proceeds from the sale of senior unsecured notes were used to repay the 2014 Credit Agreement's outstanding term loan. In June 2015, TEP terminated the 2014 Credit Agreement.

2010 Credit Agreement

In August 2015, $82 million of LOCs supporting variable-rate tax-exempt bonds were terminated after the related bonds were redeemed. As of September 30, 2015, there was $199 million available under the 2010 Credit Agreement's revolving credit facility. In October 2015, TEP terminated the 2010 Credit Agreement and replaced it with the 2015 Credit Agreement.

2010 REIMBURSEMENT AGREEMENT

The 2010 Reimbursement Agreement supports $37 million aggregate principal amount of variable rate tax-exempt bonds and includes fees payable on the aggregate outstanding amount. The rate currently in effect to maintain the LOC decreased to 0.75% per annum after TEP's credit rating upgrade in February 2015 by Moody's to A3.

COVENANT COMPLIANCE

At September 30, 2015, we were in compliance with the terms of our loan and credit agreements.

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NOTE 5. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS
COMMITMENTS
In addition to those reported in our 2014 Annual Report on Form 10-K, TEP entered into the following long-term commitments through September 30, 2015:

(in millions)	2015	2016	2017	2018	2019	Thereafter	Total
Fuel, Including Transportation	$1	$2	$2	$2	$2	$46	$55
Purchased Power	—	31	—	—	—	—	31
Renewable Power Purchase Agreements	6	16	16	16	16	245	315
Total Purchase Commitments	$7	$49	$18	$18	$18	$291	$401

Fuel
TEP entered into a new gas transportation commitment in 2015 with total minimum payment obligations expiring in 2040.
Purchased Power
TEP entered into new forward purchased power commitments in 2015 with total minimum payment obligations expiring in 2016. TEP's purchase power commitments fluctuate with changes in the market price of electricity. The commitment amount included in the table above is based on projected market prices as of September 30, 2015.
Renewable Power Purchase Agreements
TEP enters into long-term renewable power purchase agreements which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. In September 2015, one of these facilities achieved commercial operation. The related contract expires in 2035. While TEP is not required to make payments under this contract if power is not delivered, estimated future payments are included in the table above.
CONTINGENCIES
Navajo Generating Station Lease Extension
Navajo Generating Station (Navajo) is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044. The participants in Navajo, including TEP, have not signed the lease amendment because certain participants have expressed an interest in discontinuing their participation in Navajo. Negotiations between the participants are ongoing, and all parties will likely agree to the terms. To become effective, this lease amendment must be signed by all of the participants, approved by the Department of the Interior, and is subject to environmental reviews. Once the lease amendment becomes effective, the participants will be responsible for additional lease costs from the date the Navajo Nation signed the lease amendment. TEP owns 7.5% of Navajo. In the first nine months of 2015, TEP recorded an additional estimated lease expense of $2 million with the expectation that the lease amendment will become effective. At September 30, 2015, TEP's Condensed Consolidated Balance Sheets reflect a total liability related to the lease amendment of $4 million recorded in Regulatory and Other Liabilities—Other.
Claims Related to Springerville Generating Station Unit 1
On November 7, 2014, the Springerville Unit 1 Third-Party Owners filed a complaint (FERC Action) against TEP with the FERC alleging that TEP had not agreed to wheel power and energy for the Third-Party Owners in the manner specified in the Springerville Unit 1 facility support agreement between TEP and the Third-Party Owners and for the cost specified by the Third-Party Owners. The Third-Party Owners requested an order from the FERC requiring such wheeling of the Third-Party Owners' energy from their Springerville Unit 1 interests beginning on January 1, 2015 to the Palo Verde switchyard and for the price specified by the Third-Party Owners. In February 2015, the FERC issued an order denying the Third-Party Owners complaint. In March 2015, the Third-Party Owners filed a request for rehearing in the FERC Action. In October 2015, the FERC denied the request for rehearing.

On December 19, 2014, the Third-Party Owners filed a complaint against TEP in the Supreme Court of the State of New York, New York County (New York Action). In response to motions filed by TEP to dismiss various counts and compel arbitration of certain matters alleged and the court's subsequent ruling on the motions, the Third-Party Owners have amended the complaint three times, dropping certain allegations and raising others in the New York Action and in the arbitration proceeding described below. As amended, the New York Action alleges, among other things, that TEP failed to properly operate, maintain, and make capital investments in Springerville Unit 1 during the term of the leases and that TEP has breached the lease transaction documents by refusing to pay certain of the Third-Party Owners’ claimed expenses. The third amended complaint seeks $71 million in liquidated damages and direct and consequential damages in an amount to be determined at trial. The Third-Party Owners have also agreed to stay their claim that TEP has not agreed to wheel power and energy as required pending the outcome of the FERC Action.

In December 2014 and January 2015, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent notices to TEP that alleged that TEP had defaulted under the Third-Party Owners’ leases. The notices demanded that TEP pay liquidated damages totaling approximately $71 million. In letters to Wilmington Trust Company, TEP denied the allegations in the notices.

On April 20, 2015, TEP filed a demand for arbitration with the American Arbitration Association (AAA) seeking an award of the Third-Party Owners' share of unreimbursed expenses and capital expenditures for Springerville Unit 1. On June 4, 2015, the Third-Party Owners filed a separate demand for arbitration with the AAA alleging, among other things, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 since the leases have expired. The Third-Party Owners’ arbitration demand seeks declaratory judgments, damages in an amount to be determined by the arbitration panel and the Third-Party Owners’ fees and expenses. TEP and the Third-Party Owners have since agreed to consolidate their arbitration demands into one proceeding. On August 17, 2015, the Third-Party Owners filed an amended arbitration demand adding claims that TEP has converted the Third-Party Owners’ water rights and certain emission reduction payments and that TEP is improperly dispatching the Third-Party Owners’ unscheduled Springerville Unit 1 power and capacity.

On October 8, 2015, the arbitration panel granted TEP’s motion for interim relief, ordering the Third-Party Owners to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 by October 22, 2015, and ordering that they timely pay their share of all future Springerville 1 expenses and expenditures during the pendency of the arbitration. Any amounts collected could be subject to refund if the arbitration panel subsequently upholds all or portions of the Third-Party Owners’ claims. The arbitration panel denied the Third-Party Owners’ motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners’ unscheduled Springerville Unit 1 power and capacity. On October 20, 2015, the Third-Party Owners informed the arbitration panel that the Owner Trustees have no available funds and are unable to make the payments required by the interim order, and requested that the panel reconsider its associated decision in the interim order. In a letter dated October 27, 2015, the arbitration panel indicated that it reconsidered its decision and declined to change it. The arbitration hearing is scheduled for July 2016.

On October 30, 2015, TEP filed a petition to confirm the interim arbitration order in the U.S. District Court for the Southern District of New York naming the Third-Party Owners as respondents. The petition seeks an order from the court confirming the interim arbitration order under the Federal Arbitration Act.

As of September 30, 2015, TEP has billed the Third-Party Owners approximately $17 million for their pro-rata share of Springerville Unit 1 expenses and $2 million for their pro-rata share of capital expenditures, none of which had been paid as of November 5, 2015.

Under the Springerville Unit 1 facility support agreement, TEP is permitted to dispatch and use any of the Third-Party Owners’ unscheduled entitlement share(s) of power from Springerville Unit 1. TEP commenced such dispatch and use for TEP’s benefit in mid-June 2015.

TEP cannot predict the outcome of the claims relating to Springerville Unit 1, and, due to the general and non-specific scope and nature of the claims, TEP cannot determine estimates of the range of loss, if any, at this time. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners and to vigorously pursue the claims it has asserted against the Third-Party Owners.

Claims Related to San Juan Generating Station

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, 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.

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court of Colorado against the Office of Surface Mining (OSM) challenging federal administrative decisions affecting seven different mines in four states issued at various times from 2007 through 2012. In its petition, WEG challenges several unrelated mining plan modification approvals, which were each separately approved by OSM. Of the fifteen claims for relief in the WEG Petition, two concern SJCC’s San Juan mine. WEG’s allegations concerning the San Juan mine arise from OSM administrative actions in 2008. WEG alleges various National Environmental Policy Act (NEPA) violations against OSM, including, but not limited to, OSM’s alleged failure to provide requisite public notice and participation, alleged failure to analyze certain environmental impacts, and alleged reliance on outdated and insufficient documents. WEG’s petition seeks various forms of relief, including a finding that the federal defendants violated NEPA by approving the mine plans, voiding, reversing, and remanding the various mining modification approvals, enjoining the federal defendants from re-issuing the mining plan approvals for the mines until compliance with NEPA has been demonstrated, and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. A stay in this matter has expired although the parties continue to engage in settlement negotiations. If WEG ultimately obtains the relief it has requested, such a ruling could require significant expenditures to reconfigure operations at the San Juan mine, impact the production of coal, and impact the economic viability of the San Juan mine and San Juan. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

In October 2011, EarthJustice, on behalf of several environmental organizations, filed a lawsuit in the U.S. 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 sought 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. TEP owns 7% of Four Corners Units 4 and 5 and is liable for its share of any resulting liabilities. In June 2015, APS, the operator of Four Corners, announced a settlement with the Environmental Protection Agency (EPA) for outstanding environmental issues related to New Source Review provisions under the Clean Air Act. The settlement calls for environmental upgrades including Selective Catalytic Reduction (SCR) upgrades already planned for under the Regional Haze regulation (see Regional Haze Rules below), environmental mitigation projects, and civil penalties. A consent decree reflecting terms of the settlement was entered by the court in August 2015, effectively closing the case. TEP's share of the additional capital, excluding the SCR upgrades, is approximately $2 million over the three year period it will take to construct the upgrades. TEP’s share of the annual O&M expenses is approximately $1 million. In addition, TEP recorded less than $1 million for its share of the one-time charges for environmental mitigation projects and civil penalties.

In May 2013, the New Mexico Taxation and Revenue Department (NMTRD) issued a notice of assessment for coal severance tax, penalties, and interest totaling $30 million to the coal supplier at Four Corners. TEP's share of the assessment is $2 million based on our ownership percentage. 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. In June 2015, the U.S. District Court ruled in favor of the Four Corners' participants. NMTRD filed an appeal of the decision on August 31, 2015. TEP cannot predict the final outcome or timing of resolution of these claims.

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. Upon expiration of the coal supply agreements, which expire between 2017 and 2031, TEP's share of reclamation costs at all three mines, in total, is expected to be $37 million. The reclamation liability recorded was $24 million at September 30, 2015 and $22 million at December 31, 2014. 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 final reclamation costs, as a component of fuel cost, to retail 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-kilovolt (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 maintain the Certificate of Environmental Compatibility (CEC) previously granted by the ACC for this project in contemplation of using the route, or a portion thereof, to serve future customers and to address reliability needs. As part of the 2013 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 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, 2015, there have been no such payment defaults under any of the remote generating station agreements. TEP's joint participation agreements for the San Juan, Navajo, Four Corners, and Luna Generating Stations expire between 2019 and 2046.

ENVIRONMENTAL MATTERS

Environmental Regulation

The EPA regulates the amount of sulfur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury, and other by-products produced 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.

Greenhouse Gas Regulation

In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets CO_2 emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that receive an extension must submit a final completed plan to the EPA by September 2018. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.
The EPA incorporated the compliance obligations for existing power plants located on Indian nations, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a

plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP plans to comment on the proposed Federal Plan impacting our facilities, including Four Corners and Navajo. TEP cannot predict the ultimate outcome of these matters.

TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville Generating Station (Springerville) ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP’s share of the cost at Springerville is estimated to be $2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be $4 million at Four Corners, $1 million at Navajo, and less than $1 million at San Juan, the majority of which are expected to be capital expenditures.

Effluent Limitation Guidelines

In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines setting technology standards and limitations for steam electric power plant discharges. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. TEP is evaluating the effects of this rule on its facilities including Navajo, San Juan, and Four Corners. Since the majority of TEP's facilities are zero discharge, TEP does not anticipate a significant financial impact.

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 Standards (MATS) rules, additional emission control equipment would have been required by April 2015. TEP, as operator of Springerville and Sundt Generating Stations, and the operators of Navajo and Four Corners received extensions until April 2016 to comply with the MATS rules.

In June 2015, the U.S. Supreme Court reversed and remanded the D.C. Circuit Court of Appeals decision in Michigan v. EPA to uphold the MATS rules requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider “cost” before determining that MATS was “appropriate and necessary.” The D.C. Circuit Court of Appeals may remand the rules to the EPA or vacate the rules.

At this time, despite the U.S. Supreme Court ruling, the MATS rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of our facilities. Additionally, Arizona has an Arizona-specific mercury rule in place that will become effective and applicable to our Arizona facilities in the event the Federal rule is struck down. Our compliance strategy ensures compliance with both the Federal and the State rule, as applicable.

TEP's share of the estimated mercury emission control costs to comply with the MATS rules includes the following:

(in millions)	Navajo	Springerville[(1)]
Capital Expenditures	$1	$5
Annual O&M Expenses	1	1

(1) Total capital expenditures and annual O&M expenses represent amounts for Springerville Units 1 and 2, with estimated costs split equally between the two units. In January 2015, TEP completed the purchase of 49.5% of Springerville Unit 1. With the completion of the purchase, the Third-Party Owners are 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 no additional capital expenditures or O&M expenses will be incurred to comply at the Four Corners, Sundt, and San Juan Generating Stations.

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 rule calls 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 land leased from the Navajo Nation, 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 NO_x, often resulting in a requirement to install SCR. Complying with the BART rule, 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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

continue to participate in these power plants. The BART provisions do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s, after the time frame as designated by the rules. Other provisions of the Regional Haze Rules requiring further emission reductions are not likely to impact Springerville operations until after 2018. TEP cannot predict the ultimate outcome of these matters.

TEP's estimated NO_x emissions control costs involved in meeting these rules are:

(in millions)	Navajo	San Juan	Four Corners	Sundt
Capital Expenditures	$28	$12	$44	$12
Annual O&M Expenses	1	1	2	6

Navajo

In August 2014, the EPA published a final Federal Implementation Plan (FIP) 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. The final BART rule includes options that accommodate potential ownership changes at the plant. The plant has until December 2019 to notify the EPA of how it will comply with the FIP.

San Juan

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) 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 February 2016. TEP owns 50% of Units 1 and 2 at San Juan. The SIP approval references a New Source Review permit issued by the New Mexico Environment Department in November 2013 which, among other things, calls for balanced draft upgrades on San Juan Unit 1 to reduce particulate matter emissions. Public Service Company of New Mexico (PNM), the operator of San Juan, is currently installing SNCR. Balanced draft modifications to San Juan Unit 1were completed in June 2015. TEP’s share of the balanced draft upgrades was approximately $22 million. Prior to the shutdown of any units at San Juan, PNM, the operator, must first obtain New Mexico Public Regulation Commission approval.

At September 30, 2015, the NBV of TEP's share in San Juan Unit 2, including construction work in progress, was $105 million. Consistent with the 2013 Rate Order, TEP has requested to apply excess depreciation reserves against the unrecovered NBV in its 2015 Rate Case.

Four Corners

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 agreed to the installation of SCR on Units 4 and 5 by July 2018. TEP owns 7% of Four Corners Units 4 and 5.

Sundt

In June 2014, the EPA issued a final rule that would require TEP to either (i) install, by mid-2017, SNCR and dry sorbent injection if Unit 4 of the H. Wilson Sundt Generating Station (Sundt) 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. Under the rule, TEP is required to notify the EPA of its decision by March 2017. TEP expects to make a final decision in 2016.

At September 30, 2015, the NBV of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered NBV in its 2015 Rate Case. The estimated NO_x emissions control costs in the table above will not be expended if Sundt is retired early.

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NOTE 6. EMPLOYEE BENEFIT PLANS

Net periodic benefit plan cost includes the following components:

	Pension Benefits		Other Retiree Benefits	
	Three Months Ended September 30,			
(in millions)	2015	2014	2015	2014
Service Cost	$3	$2	$1	$1
Interest Cost	5	4	—	—
Expected Return on Plan Assets	(6)	(5)	—	—
Amortization of Net Loss/(Gain)	2	1	—	—
Net Periodic Benefit Cost	$4	$2	$1	$1

	Pension Benefits		Other Retiree Benefits	
	Nine Months Ended September 30,			
(in millions)	2015	2014	2015	2014
Service Cost	$9	$7	$3	$3
Interest Cost	13	12	2	2
Expected Return on Plan Assets	(18)	(16)	(1)	(1)
Amortization of Net Loss/(Gain)	6	3	—	—
Net Periodic Benefit Cost	$10	$6	$4	$4

NOTE 7. SUPPLEMENTAL CASH FLOW INFORMATION

SIGNIFICANT INVESTING AND FINANCING NON-CASH TRANSACTIONS

	Nine Months Ended September 30,	
(in millions)	2015	2014
Accrued Capital Expenditures	$21	$19
Commitment to Purchase Capital Lease Interests	—	109

NOTE 8. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

We categorize our financial instruments 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

(in millions)	Level 1	Level 2	Level 3	Total
	September 30, 2015			
Assets				
Cash Equivalents[1]	$46	$—	$—	$46
Restricted Cash[1]	2	—	—	2
Energy Derivative Contracts - Regulatory Recovery[2]	—	—	1	1
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	2	2
Total Assets	48	—	3	51
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(9)	(3)	(12)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(12)	(3)	(15)
Net Total Assets (Liabilities)	$48	$(12)	$—	$36

(in millions)	Level 1	Level 2	Level 3	Total
	December 31, 2014			
Assets				
Cash Equivalents[1]	$15	$—	$—	$15
Restricted Cash[1]	2	—	—	2
Energy Derivative Contracts - Regulatory Recovery[2]	—	—	2	2
Total Assets	17	—	2	19
Liabilities				
Energy Derivative Contracts - Regulatory Recovery[2]	—	(9)	(9)	(18)
Energy Derivative Contracts - No Regulatory Recovery[2]	—	—	(1)	(1)
Energy Derivative Contracts - Cash Flow Hedge[2]	—	—	(1)	(1)
Interest Rate Swap[3]	—	(5)	—	(5)
Total Liabilities	—	(14)	(11)	(25)
Net Total Assets (Liabilities)	$17	$(14)	$(9)	$(6)

(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 Condensed Consolidated Balance Sheets. Restricted Cash is included in Investments and Other Property on the Condensed Consolidated Balance Sheets.

(2) Energy Contracts include gas swap agreements (Level 2), power options (Level 2), gas options (Level 3), forward power purchase and sales contracts (Level 3) entered into to reduce exposure to energy price risk, and, at December 31, 2014, a power sale option (Level 3). These contracts are included in Derivative Instruments on the Condensed Consolidated Balance Sheets. The valuation techniques are described below.

(3)

An Interest Rate Swap, valued using an income valuation approach based on the 6-month LIBOR, is included in Derivative Instruments on the Condensed Consolidated Balance Sheets.

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All energy derivative contracts are subject to legally enforceable master netting arrangements to mitigate credit risk. We present derivatives on a gross basis on the balance sheet. The table below presents the potential offset of counterparty netting and cash collateral.

	Gross Amount Recognized on the Balance Sheets	Gross Amount Not Offset on the Balance Sheets Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
(in millions)	September 30, 2015			
Derivative Assets				
Energy Derivative Contracts	$3	$1	$—	$2
Derivative Liabilities				
Energy Derivative Contracts	(12)	(1)	—	(11)
Interest Rate Swap	(3)	—	—	(3)

	Gross Amount Recognized on the Balance Sheets	Gross Amount Not Offset on the Balance Sheets Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
(in millions)	December 31, 2014			
Derivative Assets				
Energy Derivative Contracts	$2	$2	$—	$—
Derivative Liabilities				
Energy Derivative Contracts	(20)	(2)	—	(18)
Interest Rate Swap	(5)	—	—	(5)

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.

The December 31, 2014 valuation of our power sale option was a function of observable market variables, regional power and gas prices, as well as the ratio between the two, which represents the prevailing market heat rate.

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.

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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 can enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. We have an interest rate swap agreement that expires January 2020. We also had a power purchase swap to hedge the cash flow risk associated with a long-term power supply agreement. The power purchase swap agreement expired in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $1 million. The realized losses from our cash flow hedges are shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Capital Lease Interest Expense	$—	$—	$1	$2
Long-Term Debt Interest Expense	—	—	—	1
Purchased Power	1	—	1	1

As of September 30, 2015 the total notional amount of our interest rate swap was $29 million.

Energy Contracts - Regulatory Recovery

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets)/Liabilities	$4	$(6)	$7	$(4)

Energy Contracts - No Regulatory Recovery

Forward contracts with long-term wholesale customers do not qualify for regulatory recovery. For these contracts that qualify as derivatives, we record unrealized gains and losses in the income statement, unless and until a normal purchase or normal sale election is made. In February 2015, TEP made a normal sale election for a three-year sales option contract entered into in December 2014. In June 2015, TEP entered into long-term power trading contracts that qualify as derivatives but do not qualify for regulatory recovery. The unrealized gains and losses on the long-term power trading contracts are recorded in the income statement, and ten percent of any gains will be shared with ratepayers through the PPFAC, as realized.

Derivative Volumes

At September 30, 2015, we have energy contracts that will settle through September 2018. The volumes associated with our energy contracts were as follows:

	September 30, 2015	December 31, 2014
Power Contracts GWh	2,509	2,604
Gas Contracts GBtu	15,490	19,932

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(in millions)	Valuation Approach	Fair Value at September 30, 2015 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
Forward Power Contracts	Market approach	$3	$(1)	Market price per MWh	$20.95	$34.60
Gas Option Contracts	Option model	—	(2)	Market price per MMbtu	$2.41	$2.92
				Gas volatility	27.78 %	45.56 %
Level 3 Energy Contracts		$3	$(3)			

(in millions)	Valuation Approach	Fair Value at December 31, 2014 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input	
Forward Power Contracts	Market approach	$1	$(6)	Market price per MWh	$22.35	$39.05
Power Sale Option	Market approach	1	(1)	Market price per MWh	$27.75	$44.94
				Market price per MMbtu	$2.88	$4.02
Gas Option Contracts	Option model	—	(4)	Market price per MMbtu	$2.72	$3.26
				Gas volatility	30.80 %	53.29 %
Level 3 Energy Contracts		$2	$(11)			

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, that are subject to recovery or refund through the PPFAC mechanism are reported on the balance sheets as a regulatory asset or regulatory liability, or as a component of other comprehensive income, rather than in the income statements.
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:

(in millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Balances at beginning of period	$(4)	$—	$(9)	$(2)
Gains/(Losses) Recorded to:[(1)]				
Net Regulatory Assets/Liabilities – Derivative Instruments	10	(4)	(3)	(3)
Electric Wholesale Sales	—	—	3	—
Settlements	(6)	—	9	1
Balances at end of period	$—	$(4)	$—	$(4)

(1)

Includes gains/(losses) attributable to the change in unrealized gains/(losses) relating to assets/(liabilities) still held at the end of the period of $(2) million for the three months ended September 30, 2015 and 2014, and $1 million and $(2) million, for the nine months ended, September 30, 2015 and 2014, respectively.

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.

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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; 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, 2015, 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 $22 million, compared with $21 million at December 31, 2014. At September 30, 2015 TEP had $1 million of LOCs as credit enhancements with its counterparties. The additional collateral to be posted if credit-risk contingent features were triggered would be $22 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 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.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts.

The carrying values recorded on the Condensed Consolidated Balance Sheets and the estimated fair values of our financial instruments include the following:

		September 30, 2015		December 31, 2014	
(in millions)	Fair Value Hierarchy	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-Term Debt	Level 2	$1,463	$1,521	$1,372	$1,457

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

NOTE 9. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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. The revenue standard requires entities to apply the guidance retrospectively or recognize the cumulative effect of initially applying the guidance as an adjustment to the opening balance of retained earnings supplemented by additional disclosures. In July 2015, the FASB voted to defer the effective date of the revenue recognition standard by one year. We will be required to adopt the new guidance for annual and interim periods beginning January 1, 2018; early adoption is permitted for annual and interim periods beginning January 1, 2017. We are in the process of identifying contracts with customers and performance obligations in contracts.

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.

In January 2015, the FASB issued an accounting standards update that removes the concept of extraordinary items from U.S. GAAP. The standard is effective for periods beginning January 1, 2016; early adoption is permitted. TEP does not expect the adoption of this guidance to impact its results of operations or disclosures.

In February 2015, the FASB issued guidance that amends the current consolidation guidance; the amendment affects both the variable interest entity and voting interest entity consolidation models. This standard is effective beginning January 1, 2016 and may be applied using a modified retrospective approach or retrospectively; early adoption is permitted. We are evaluating the impact to our financial statements and disclosures.

In April 2015, the FASB issued guidance which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability, rather than as deferred charges. The amendment is effective for periods beginning January 1, 2016 and will be applied retrospectively; early adoption is permitted. The adoption of this standard is expected to result in reclassification of debt issuance costs from Other Current Assets and Other Assets to Long-Term Debt on our balance sheet. TEP’s deferred debt issuance costs associated with long-term debt outstanding totaled $12 million at September 30, 2015 and $11 million at December 31, 2014, of which approximately $1 million was classified as current at each date. In August 2015, the FASB added guidance indicating that the SEC staff would not object to an entity deferring and presenting debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on a line-of-credit arrangement. TEP expects to continue accounting for debt issuance costs related to line-of-credit arrangements as an asset.

In April 2015, the FASB issued guidance that will help entities evaluate the accounting for fees paid by a customer in a cloud computing arrangement either as a software license or a service contract. The standard is effective for periods beginning January 1, 2016; early adoption is permitted. An entity can elect to adopt the amendment prospectively or retrospectively. TEP does not expect the adoption of this guidance to have a material impact on our disclosures, financial condition, results of operations, or cash flows.

In July 2015, the FASB issued guidance which requires inventory using any method other than LIFO or the retail inventory method to be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The amendment is effective for periods beginning January 1, 2017 and will be applied prospectively; early adoption is permitted. TEP does not expect the adoption of this guidance to have a material impact on our disclosures, financial condition, results of operations, or cash flows.

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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 Tucson Electric Power Company (TEP). It includes the following:

- outlook and strategies;
- operating results during the third quarter and first nine months of 2015 compared with the same periods of 2014;
- factors affecting our results and outlook;
- liquidity and capital resources including contractual obligations;
- critical accounting estimates; and
- recent accounting pronouncements.

Management’s Discussion and Analysis includes financial information prepared in accordance with generally accepted accounting principles in the United States of America (GAAP), as well as certain non-GAAP financial measures. The non-GAAP financial measures should be viewed as a supplement to, and not a substitute for, financial measures presented in accordance with GAAP. Non-GAAP financial measures as presented herein may not be comparable to similarly titled measures used by other companies.

Management’s Discussion and Analysis should be read in conjunction with the Condensed Consolidated Financial Statements and accompanying notes that appear in Item 1 of this Form 10-Q. For information on factors that may cause our actual future results to differ from those we currently seek or anticipate, see Forward-Looking Information at the front of this report and Risk Factors in Part 1, Item 1A of our 2014 Annual Report Form 10-K, and in Part II, Item 1A of this report.

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

OVERVIEW

TEP delivers safe, reliable power to more than 417,000 customers in the Tucson metropolitan area. TEP is the second-largest investor-owned utility in Arizona and the largest corporation headquartered in Southern Arizona. TEP offers comprehensive energy services through reliable, traditional resources, and a growing renewable power portfolio. We also offer many ways to help our customers use energy more efficiently.

In August 2014, Fortis Inc. (Fortis) completed the acquisition of UNS Energy Corporation (UNS Energy), TEP’s parent company. TEP and its sister company, UniSource Energy Services (UES), are among a family of utilities owned by Fortis, which is a leader in the North American electric and gas utility business.

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.

During the first nine months of 2015, we continued to execute on the following five strategies:

- Continuing to focus on our long-term generation resource strategy, including shifting from coal to natural gas, renewables, distributed generation, and energy efficiency while providing rate stability for our customers, mitigating environmental impacts, complying with regulatory requirements, leveraging our existing utility infrastructure, and maintaining financial strength.
- Developing strategic responses to new environmental regulations and potential new legislation, including new 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 and the interests of our customers.
- 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.

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- Focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.
- Achieving a constructive outcome in our pending rate case proceeding that provides TEP recovery of its cost of service and an opportunity to earn a fair rate of return on its rate base investments, updates TEP's rates to provide more accurate price signals, a more equitable allocation of costs to its customers, and enables TEP to continue providing safe and reliable service.

2015 FINANCIAL HIGHLIGHTS

The first nine months of 2015 included the following notable items:

- In January 2015, TEP purchased additional undivided ownership interests in Springerville Unit 1;
- In January 2015, TEP purchased existing unsecured tax-exempt industrial development revenue bonds in the amount of $130 million;
- In February 2015, TEP issued and sold $300 million of unsecured notes;
- In April 2015, TEP purchased undivided ownership interests in the Springerville Coal Handling Facilities, bringing its total ownership interest to 100%;
- In May 2015, TEP sold an undivided ownership interest in Springerville Coal Handling Facilities to SRP; and
- In June 2015, TEP received an equity contribution of $180 million from UNS Energy.

In addition, on October 15, 2015, TEP entered into a new unsecured credit agreement (2015 Credit Agreement) that provides for a $250 million revolving credit and Letter of Credit (LOC) facility. The new credit agreement matures in 2020 and replaces the 2010 Credit Agreement.

On November 5, 2015, TEP filed a general rate case with the Arizona Corporation Commission (ACC) that requests, among other things, a Base Rate increase of $110 million. The application also requests that new rates become effective no later than January 1, 2017.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations during the third quarter and first nine months of 2015 compared with the same periods in 2014. The significant items affecting net income are presented on an after-tax basis.

Third quarter of 2015 compared with the third quarter of 2014

TEP reported net income of $69 million in the third quarter of 2015 compared with $40 million from the third quarter of 2014. The increase of $29 million, or 72.9%, was primarily due to:

- $20 million of lower Base O&M resulting primarily from merger costs recorded in 2014, partially offset by higher O&M related to Gila River Unit 3 and labor costs;
- $3 million of higher retail margin revenue primarily due to hotter weather resulting in higher retail customer demand and an increase in Lost Fixed Cost Recovery (LFCR) revenues; and
- $2 million of higher transmission revenue resulting primarily from an increase in sales volume on favorably priced contracts.

Nine months ended September 30, 2015 compared with the nine months ended September 30, 2014

TEP reported net income of $116 million in the first nine months of 2015 compared with $88 million from the first nine months of 2014. The increase of $28 million, or 32.3%, was primarily due to:

- $17 million of lower Base O&M resulting primarily from merger costs recorded in 2014, partially offset by higher O&M related to Gila River Unit 3 and labor costs;

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- $6 million of higher transmission revenue resulting primarily from an increase in sales volume on favorably priced contracts; and
- $4 million in lower interest expense primarily due to a reduction in the balance of capital lease obligations. See Note 4 to the Condensed Consolidated Financial Statements.

The increase was partially offset by $2 million of higher property taxes due to a higher asset base.

Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data for the third quarter of 2015 and 2014:

	Three Months Ended September 30,		Increase (Decrease)	
	2015	2014	Amount	Percent
Electric Retail Sales (kWh in millions)				
Residential	1,350	1,334	16	1.2 %
Commercial	637	642	(5)	(0.8)%
Industrial	607	602	5	0.8 %
Mining	279	287	(8)	(2.8)%
Public Authorities	6	7	(1)	(14.3)%
Total Electric Retail Sales	2,879	2,872	7	0.2 %
Retail Margin Revenues (in millions)				
Residential	$101	$100	$1	1.0 %
Commercial	61	61	—	— %
Industrial	31	30	1	3.3 %
Mining	11	11	—	— %
Public Authorities	—	—	—	— %
Total by Customer Class	204	202	2	1.0 %
LFCR Revenues	3	2	1	NM
Other Retail Margin Revenues	2	—	2	NM
Total Retail Margin Revenues (Non-GAAP)(1)	209	204	5	2.5 %
Fuel and Purchased Power Revenues	116	101	15	14.9 %
DSM and RES Surcharge Revenues	12	11	1	9.1 %
Total Retail Revenues (GAAP)	$337	$316	$21	6.6 %
Average Retail Margin Rate (cents / kWh)(2)				
Residential	7.48	7.50	(0.02)	(0.3)%
Commercial	9.58	9.50	0.08	0.8 %
Industrial	5.11	4.98	0.13	2.6 %
Mining	3.94	3.83	0.11	2.9 %
Public Authorities	5.78	5.70	0.08	1.4 %
Total Average Margin Rate by Customer Class	7.09	7.03	0.06	0.9 %
Total Average Retail Margin Rate(3)	7.26	7.10	0.16	2.3 %
Average Fuel and Purchased Power Rate	4.03	3.52	0.51	14.5 %
Average DSM and RES Surcharge Rate	0.42	0.38	0.04	10.5 %
Total Average Retail Rate	11.71	11.00	0.71	6.5 %
Weather Data				
Cooling Degree Days				
Three Months Ended September 30,	1,033	964	69	7.2 %
10-Year Average	1,001	1,000	1	0.1 %

(1) 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 kilowatt-hour (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, LFCR revenues, Demand Side Management (DSM) performance bonus, and certain other retail margin revenues available to cover the non-fuel operating expenses of our core utility business.

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(2) Calculated on unrounded data and may not correspond exactly to data shown in table.
(3) Total Average Retail Margin Rates include revenues related to LFCR and Other Retail Margin Revenues included in the Total Retail Margin Revenues.

Retail Revenues were higher in the third quarter of 2015 when compared to 2014, primarily due to an increase in the Purchased Power and Fuel Adjustment Clause (PPFAC) rate and higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to hotter weather resulting in higher retail customer demand and an increase in LFCR revenues.

The table below provides a summary of retail kWh sales, revenues, and weather data for the first nine months of 2015 and 2014:

	Nine Months Ended September 30,		Increase (Decrease)	
	2015	2014	Amount	Percent
Electric Retail Sales (kWh in millions)				
Residential	2,954	2,987	(33)	(1.1)%
Commercial	1,635	1,671	(36)	(2.2)%
Industrial	1,590	1,599	(9)	(0.6)%
Mining	832	850	(18)	(2.1)%
Public Authorities	23	24	(1)	(4.2)%
Total Electric Retail Sales	7,034	7,131	(97)	(1.4)%
Retail Margin Revenues (in millions)				
Residential	$223	$225	$(2)	(0.9)%
Commercial	147	149	(2)	(1.3)%
Industrial	81	80	1	1.3%
Mining	29	30	(1)	(3.3)%
Public Authorities	1	1	—	—%
Total by Customer Class	481	485	(4)	(0.8)%
LFCR Revenues	9	8	1	12.5%
DSM Performance Bonus	3	2	1	NM
Other Retail Margin Revenues	4	—	4	NM
Total Retail Margin Revenues (Non-GAAP)(1)	497	495	2	0.4%
Fuel and Purchased Power Revenues	270	233	37	15.9%
DSM and RES Surcharge Revenues	36	32	4	12.5%
Total Retail Revenues (GAAP)	$803	$760	$43	5.7%
Average Retail Margin Rate (cents / kWh)(2)				
Residential	7.55	7.53	0.02	0.3%
Commercial	8.99	8.92	0.07	0.8%
Industrial	5.09	5.00	0.09	1.8%
Mining	3.49	3.53	(0.04)	(1.1)%
Public Authorities	5.66	5.64	0.02	0.4%
Total Average Margin Rate by Customer Class	6.84	6.80	0.04	0.6%
Total Average Retail Margin Rate(3)	7.07	6.94	0.13	1.9%
Average Fuel and Purchased Power Rate	3.84	3.27	0.57	17.4%
Average DSM and RES Rate	0.51	0.45	0.06	13.3%
Total Average Retail Rate	11.42	10.66	0.76	7.1%
Weather Data				
Cooling Degree Days				
Nine Months Ended September 30, 2015	1,516	1,514	2	0.1%
10-Year Average	1,481	1,477	4	0.3%
Heating Degree Days				

Nine Months Ended September 30, 2015	452	455	(3)	(0.7)%
10-Year Average	784	820	(36)	(4.4)%

(1) 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, LFCR revenues, DSM performance bonus, and certain other retail margin revenues available to cover the non-fuel operating expenses of our core utility business.

(2) Calculated on unrounded data and may not correspond exactly to data shown in table.

(3) Total Average Retail Margin Rates include revenues related to LFCR, DSM Performance Bonus, and Other Retail Margin Revenues included in the Total Retail Margin Revenues.

Retail Revenues were higher in the first nine months of 2015 when compared to 2014 primarily due to the increase in the PPFAC rate and higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to higher LFCR Revenues, DSM Performance Bonus and Other Retail Margin Revenues not offset in expenses.

Wholesale Sales and Transmission Revenues

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Long-Term Wholesale Revenues:				
Long-Term Wholesale Margin Revenues (Non-GAAP)[1]	$3	$2	$9	$8
Fuel and Purchased Power Expense Allocated to Long-Term Wholesale Revenues	7	4	20	13
Total Long-Term Wholesale Revenues	10	6	29	21
Transmission Revenues	7	4	21	12
Short-Term Wholesale Revenues	24	27	80	79
Electric Wholesale Sales (GAAP)	$41	$37	$130	$112

(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 increased by $1 million in the third quarter of 2015 compared to 2014 primarily due to new wholesale agreements, partially offset by lower wholesale market prices. Transmission revenues increased by $3 million in the third quarter of 2015 compared to 2014 due to an increase in sales volume related to favorably priced contracts.

Long-Term Wholesale Margin Revenues increased by $1 million in the first nine months of 2015 compared to 2014 primarily due to new wholesale agreements, partially offset by lower wholesale market prices. Transmission revenues increased by $9 million in the first nine months of 2015 compared to 2014 due to an increase in sales volume related to favorably priced contracts.

The majority of revenues from short-term wholesale sales is related to ACC jurisdictional assets and 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,	
(in millions)	2015	2014	2015	2014
Revenue Related to Springerville Units 3 and 4[1]	$24	$26	$69	$71
Other Revenue	7	8	20	22
Total Other Revenue	$31	$34	$89	$93

(1) Represents revenues and reimbursements from Tri-State Generation and Transmission Association, Inc. (Tri-State), the lessee of Springerville Unit 3, and Salt River Project Agricultural Improvement and Power District

(SRP), the owner of Springerville Unit 4, to TEP related to the operation of these plants.
In addition to reimbursements related to Springerville Units 3 and 4, TEP’s other revenues include inter-company revenues from its affiliates, UNS Gas, Inc. (UNS Gas) and UNS Electric, Inc. (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.

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There were no significant changes noted in the third quarter and first nine months of 2015 when compared to the same periods in 2014.

Operating Expenses

Generating Output and Fuel and Purchased Power Expense

TEP’s fuel and purchased power expense and energy resources are detailed in the following tables:

	Generation and Purchased Power (kWh)		Fuel and Purchased Power Expense	
	Three Months Ended September 30,			
(in millions)	2015	2014	2015	2014
Coal-Fired Generation	2,362	2,536	$57	$65
Gas-Fired Generation	885	464	34	23
Utility Owned Renewable Generation	13	14	—	—
Fuel Expense for Springerville Units 3 and 4(1)	—	—	1	1
Total Generation	3,260	3,014	92	89
Total Purchased Power	915	1,001	40	50
Transmission and Other PPFAC Recoverable Costs	—	—	7	5
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	10	(5)
Total Generation and Purchased Power	4,175	4,015	$149	$139
Less Line Losses and Company Use	(277)	(279)		
Total Energy Sold	3,898	3,736		

(1) Springerville Unit 3 and 4 Fuel Expense is reimbursed by Tri-State and SRP.

Total Fuel and Purchased Power Expense increased by $10 million, or 7.2%, in the third quarter of 2015 compared to 2014 primarily due to an increase related to current year recovery of 2014 PPFAC amounts and additional generation and transmission costs associated with Gila River Unit 3. These increases have been partially offset by lower purchased power and a decrease in coal generation at Springerville Unit 1 related to the lease expiration in January 2015.

	Generation and Purchased Power (kWh)		Fuel and Purchased Power Expense	
	Nine Months Ended September 30,			
(in millions)	2015	2014	2015	2014
Coal-Fired Generation	6,500	6,739	$167	$170
Gas-Fired Generation	1,876	1,009	68	51
Utility Owned Renewable Generation	49	38	—	—
Fuel Expense for Springerville Units 3 and 4(1)	—	—	4	4
Total Generation	8,425	7,786	239	225
Total Purchased Power	2,711	2,548	108	125
Transmission and Other PPFAC Recoverable Costs	—	—	19	13
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	21	(20)
Total Generation and Purchased Power	11,136	10,334	$387	$343
Less Line Losses and Company Use	(611)	(678)		
Total Energy Sold	10,525	9,656		

(1) Springerville Unit 3 and 4 Fuel Expense is reimbursed by Tri-State and SRP.

Fuel and Purchased Power Expense increased by $44 million, or 12.8%, in the first nine months of 2015 compared to 2014 primarily due to an increase related to current year recovery of 2014 PPFAC amounts and additional generation and

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transmission costs associated with Gila River Unit 3. These increases have been partially offset by lower purchased power and a decrease in coal generation at Springerville Unit 1 related to the lease expiration in January 2015.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(cents per kWh)	2015	2014	2015	2014
Coal	2.39	2.55	2.58	2.53
Gas	3.86	5.04	3.61	5.03
Purchased Power	4.41	4.99	3.97	4.92
All Sources	3.58	3.86	3.48	3.76

O&M

The table below summarizes the items included in O&M expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Base O&M (Non-GAAP)(1)	$64	$96	$190	$218
O&M Recorded in Other Expense	—	(6)	—	(10)
Reimbursed Expenses Related to Springerville Units 3 and 4(2)	17	18	49	49
Expenses Related to Customer Funded Renewable Energy and DSM Programs(3)	7	5	17	17
Total O&M (GAAP)	$88	$113	$256	$274

(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) Expenses related to Springerville Units 3 and 4 are reimbursed with corresponding amounts recorded in Other Revenue. The Third-Party Owners' share of expenses related to Springerville Unit 1 is included in Base O&M.

(3) These expenses are being collected from customers and the corresponding amounts are recorded in retail revenue.

Total O&M decreased by $25 million, or 22.1%, in the third quarter of 2015 compared to 2014 primarily due to $33 million of merger-related expenses and retail customer bill credits included in 2014. The decrease was partially offset by higher O&M related to Gila River Unit 3 and labor costs.

Total O&M decreased by $18 million, or 6.6%, in the first nine months of 2015 compared to 2014 primarily due to $34 million of merger-related expenses and retail customer bill credits included in 2014. The decrease was partially offset by higher O&M related to Gila River Unit 3 and labor costs.

FACTORS AFFECTING RESULTS OF OPERATIONS

Regulatory Matters

TEP is subject to comprehensive regulation. The discussion below contains material developments to those matters disclosed in Item 7 of our 2014 Annual Report Form 10-K, and new regulatory matters occurring in 2015.

2015 Rate Case

On November 5, 2015, TEP filed a general rate case with the ACC to: (i) update and improve its rate design and tariffs to provide more accurate price signals and a more equitable allocation of its fixed costs to its customers; (ii) provide TEP with an opportunity to recover its full cost of service, including an appropriate return on its rate base investments; and (iii) enable TEP to continue to provide safe and reliable service. The rate application is based on a test year ended June 30, 2015. The filing requests that new rates be implemented by January 1, 2017.

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The key provisions of the rate case include:

- a Base Rate increase of $110 million, or 12.0%, compared with adjusted test year revenues;
- a 7.34% return on original cost rate base of $2.1 billion, which includes approximately $73 million of post-test year adjustments for utility plant that is expected to be in service by December 31, 2016;
- a capital structure for rate making purposes of approximately 50% common equity and 50% long-term debt;
- a cost of equity of 10.35% and an average cost of debt of 4.32%;
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of San Juan Unit 2 and the Sundt Coal Handling Facilities due to early retirement;
- a request for authority to begin using the Third-Party Owners' portion of Springerville Unit 1 that is available to TEP for dispatch to serve retail customer needs and to recover the related operating costs through the PPFAC; and
- rate design changes that would reduce the reliance on volumetric sales to recover fixed costs, and a new net metering tariff that would ensure that customers who install distributed generation pay an equitable price for their electric service.

TEP cannot predict the outcome of this proceeding or whether its rate request will be adopted by the ACC in whole or in part.

Generating Resources

At September 30, 2015, approximately 49% of TEP's generating capacity was fueled by coal. 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 strategies and evaluating additional steps to reduce its dependency on coal generation. In August 2015, TEP exhausted its existing coal supply at Unit 4 of the H. Wilson Sundt Generating Station (Sundt Unit 4). Currently, TEP expects to operate Sundt Unit 4 on natural gas as a primary fuel source. TEP's ability to further reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- Regulatory approvals associated with the anticipated closure of San Juan Unit 2, and pending ownership restructuring of the remaining units;
- The impact of the Clean Power Plan on current coal-fired generating facilities; and
- The ability to resolve Springerville Unit 1 legal proceedings relating to the Third-Party Owners.

See Note 5 to the Condensed Consolidated Financial Statements for more information.

Springerville Unit 1

TEP leased 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 were accounted for as capital leases. The leases expired in January 2015. At that time, TEP purchased a leased interest comprising 24.8% of Springerville Unit 1, representing 96 megawatts (MW) of capacity, for an aggregate purchase price of $46 million. Following this purchase, TEP owns 49.5% of Springerville Unit 1, or 192 MW of capacity.

The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, is owned by Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee under a separate trust agreement with each of the remaining two owner participants, Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners). TEP is not obligated to purchase any of the Third-Party Owners’ generating output. TEP is obligated to operate the unit for the Third-Party Owners. The Third-Party Owners are obligated to compensate TEP for their pro rata share of expenses for the unit in the amount of approximately $2 million per month, and their share of capital expenditures, which are expected to be approximately $4 million in 2015.

On April 20, 2015, TEP filed a demand for arbitration seeking an award of the Third-Party Owners share of unreimbursed expense and capital expenditures for Springerville Unit 1. On October 8, 2015, the arbitration panel granted TEP’s motion for interim relief, ordering the Third-Party Owners to pay TEP their pro-rata share of unreimbursed expenses and capital expenditures for Springerville Unit 1 during the pendency of the arbitration. The arbitration panel also denied the Third-Party Owners’ motion for interim relief which had requested that TEP be enjoined from dispatching the Third-Party Owners'

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unscheduled Springerville Unit 1 power and capacity. TEP has been scheduling the Third-Party Owners' entitlement share of power from Springerville Unit 1, as permitted under the Springerville Unit 1 facility support agreement, since June 14, 2015. On October 20, 2015, the Third-Party Owners informed the arbitration panel that the Owner Trustees have no available funds and are unable to make the payments required by the interim order, and requested that the panel reconsider its associated decision in the interim order. In a letter dated October 27, 2015, the arbitration panel indicated that it reconsidered its decision and declined to change it. As of September 30, 2015, TEP has billed the Third-Party Owners approximately $17 million for their pro-rata share of Springerville Unit 1 expenses and $2 million for their pro-rata share of capital expenditures, none of which had been paid as of November 5, 2015.

See Note 5 to the Condensed Consolidated Financial Statements for a description of legal proceedings relating to the Third-Party Owners.

Potential Plant Retirements

TEP's 2014 Integrated Resource Plan (IRP), which was acknowledged by the ACC in April 2015, reflected plans to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) by 2018. TEP's 2014 IRP reference case included retiring certain coal-fired generating facilities at San Juan Generating Station (San Juan) and coal handling facilities at the H. Wilson Sundt Generating Station (Sundt) earlier than their current estimated useful lives. These facilities currently do not have the requisite emission control equipment to meet proposed Environmental Protection Agency (EPA) regulations. TEP plans to seek regulatory recovery for amounts that would not otherwise be recovered if and when any assets are retired. TEP is required to file its next IRP by April 2017.

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

Springerville Coal Handling Facilities Capital Lease Purchase

TEP previously leased 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 had an initial term that expired in April 2015 and provided TEP the option to renew the leases or to purchase the leased interests at the aggregate fixed price of $120 million. In April 2015, TEP exercised its option to purchase the facilities.

Upon the expiration of the lease term, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities bringing TEP's total ownership interest to 100%. With the completion of the purchase, SRP was obligated to buy a 17.05% undivided interest in the Springerville Coal Handling Facilities from TEP for approximately $24 million. This transaction was completed in May 2015. Tri-State, is obligated to either: 1) buy a 17.05% undivided interest in the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. Tri-State has until April 2016 to exercise its purchase option.

Interest Rates

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

Fair Value Measurements

See Note 8 to the Condensed Consolidated Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

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 seasonal cash flow, TEP will use its revolving credit facility, as needed, to fund its business activities.

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The table below presents net cash provided by (used for) operating, investing and financing activities:

	Nine Months Ended September 30,	
(in millions)	2015	2014
Net Cash Flows – Operating Activities	$266	$221
Net Cash Flows – Investing Activities	(419)	(236)
Net Cash Flows – Financing Activities	146	18
Net Increase (Decrease) in Cash	(7)	3
Beginning Cash	74	25
Ending Cash	$67	$28

Liquidity Outlook

We believe that we have sufficient liquidity under our revolving credit facilities to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements. The following highlight material changes to TEP's sources of liquidity in the first nine months of 2015:

- In February 2015, TEP issued long-term debt. Proceeds from the issuance of the long-term debt were used to repay revolving and term loans under its credit agreements and to pay a portion of the purchase price for interests in the Springerville Coal Handling Facilities.
- In June 2015, UNS Energy made an equity contribution to TEP. TEP used proceeds from the equity contribution to repay the outstanding balances under TEP's revolving credit facilities.
- In August 2015, TEP used proceeds from the equity contribution to redeem long-term variable rate tax-exempt bonds which were irrevocably called for redemption in June 2015.

In addition, on October 15, 2015, TEP terminated the 2010 Credit Agreement and replaced it with the 2015 Credit Agreement.

Operating Activities

In the first nine months of 2015, net cash flows from operating activities increased by $45 million compared to the same period last year primarily due to:

- $33 million of higher cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid driven primarily by an increase in the average PPFAC rate. See Note 2 to the Condensed Consolidated Financial Statements;
- $19 million of lower cash paid for incentive compensation primarily due to the 2014 merger;
- $15 million of lower cash paid for merger-related costs; and
- $14 million of lower cash paid for interest on debt and capital leases, net of amounts capitalized.

The increase in net cash flows from operating activities was partially offset by:

- $16 million of higher cash paid for pension and retiree funding;
- $7 million of lower cash receipts from the San Juan mine fire claim settlement;
- $7 million of higher cash paid for self-insured medical expenses; and
- $3 million of higher cash paid for managements fees to Fortis in 2015.

Investing Activities

In the first nine months of 2015, net cash flows used for investing activities increased by $183 million compared with the same period last year primarily due to:

- $120 million purchase, in April 2015, of an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities increasing its total ownership interest to 100% ;

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- $46 million purchase, in January 2015, of an additional 24.8% undivided ownership interest in Springerville Unit 1 increasing its total ownership interest to 49.5%;
- $32 million of higher capital expenditures to fund system reinforcement through replacements and betterments, with the majority of funds being used for the construction of a new 500kV transmission line; and
- $5 million of lower contributions in aid of construction received.

The increase in net cash flows used for investing activities was partially offset by the sale, in May 2015, of a 17.05% undivided ownership interest in Springerville Coal Handling Facilities to SRP for approximately $24 million.

Financing Activities

In the first nine months of 2015, net cash flows from financing activities increased by $128 million compared to the same period last year primarily due to:

- $180 million in higher cash proceeds from UNS Energy's equity contribution, in June 2015;
- $152 million in lower cash payments due to the expiration of capital lease obligations in 2015; and
- $150 million in higher cash proceeds from the issuance of long-term debt, in February 2015.

The increase in net cash flows from financing activities was partially offset by:

- $209 million in higher cash payments due to the purchase of $130 million in tax-exempt long-term debt, in January 2015, and retirement of $79 million in August 2015;
- $120 million in lower proceeds borrowed and higher repayments under TEP's revolving credit facilities; and
- $25 million in higher cash dividend payments, in July 2015.

Debt Issuance and Redemption

In January 2015, amounts borrowed under the term loan portion of the 2014 Credit Agreement were used to purchase $130 million aggregate principal amount of unsecured bonds. The multi-modal bonds mature in September 2029 and at September 30, 2015, TEP had not canceled or remarketed them.

In February 2015, TEP issued and sold $300 million of unsecured notes. The notes bear interest at a fixed rate of 3.05%, and mature in March 2025. TEP may redeem the notes prior to December 15, 2024, with a make-whole premium plus accrued interest. On or after December 15, 2024, TEP may redeem the notes at par plus accrued interest.

In March 2015, TEP used the net proceeds from the bond sale to repay $215 million of revolving and term loans under its 2014 Credit Agreement and 2010 Credit Agreement. In April 2015, TEP used the remaining amount to pay a portion of the purchase price for an additional interest in the Springerville Coal Handling Facilities. See Note 4 to the Condensed Consolidated Financial Statements.

In June 2015, TEP issued an irrevocable notice to redeem approximately $79 million of variable rate tax-exempt bonds. In August 2015, TEP redeemed the bonds using proceeds from the UNS Energy equity contribution.

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Credit and Debt Agreements

(in millions)	Expires[1]	At September 30, 2015 Facility Size	LOC Outstanding	Borrowings	Available Balance	As of November 5, 2015 Available Balance
2010 Credit Agreement[2]	November 2016					
Revolving Credit and LOC Facility		$200	$1	$—	$199	$—
LOC Facility[3]		82	—	—	—	—
2015 Credit Agreement[4]	October 2020					
Revolving Credit and LOC Facility		—	—	—	—	250
Reimbursement Agreement[5]	February 2019					
LOC Facility		37	37	—	—	—

(1) In June 2015, TEP terminated the 2014 Credit Agreement.
(2) In October 2015, TEP terminated the 2010 Credit Agreement.
(3) In September 2015, $82 million of LOCs supporting variable-rate tax-exempt bonds were terminated. Redemption of the related bonds was completed in August 2015.
(4) In October 2015, TEP entered into an unsecured credit agreement (2015 Credit Agreement). The credit agreement provides for a $250 million revolving credit and LOC facility with a sublimit of $50 million.
(5) The LOC supports variable rate tax-exempt pollution control bonds and includes fees payable on the aggregate outstanding amount. The rate currently in effect after Moody's credit upgrade in February 2015 is 0.75% per annum.

Restrictive Debt Covenants

Certain of TEP's credit and variable-rate debt agreements 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 facilities. At September 30, 2015, TEP's unsecured credit ratings were A3 from Moody's and BBB+ from Standard & Poor's. The agreements also contain restrictions on mergers and sales of assets as well as a maximum leverage test. The agreements include conditions of default that would entitle the lenders to accelerate the maturity of all amounts outstanding. At September 30, 2015, TEP was in compliance with all covenants related to its credit agreements. See Note 4 to the Condensed Consolidated Financial Statements.

Capital Lease Obligations

In January 2015, TEP purchased an additional undivided ownership interest in Springerville Unit 1. In April 2015, TEP purchased the remaining undivided ownership interest in the Springerville Coal Handling Facilities. Accordingly, at September 30, 2015, there was no capital lease obligation balance for Springerville Unit 1 or the Springerville Coal Handling Facilities.

The table below provides a summary of the outstanding capital lease obligations:

(in millions)	September 30, 2015	Expiration	Renewal/Purchase Option
Springerville Common Facilities[1]	$68	2017 and 2021	Fixed price purchase option of $106 million

(1)

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

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

Contractual Obligations

There have been no changes in TEP's contractual obligations or other commercial commitments from those reported in our 2014 Annual Report on Form 10-K, other than the following changes in 2015:

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- TEP issued and sold $300 million of its senior unsecured notes. The notes bear an interest at the fixed rate of 3.05% and mature March 15, 2025. See Note 4 to the Condensed Consolidated Financial Statements.
- TEP repurchased $130 million aggregate principal amount of unsecured bonds. See Note 4 to the Condensed Consolidated Financial Statements.
- TEP redeemed approximately $79 million of variable rate tax-exempt bonds using proceeds from the UNS Energy equity contribution. See Note 4 to the Condensed Consolidated Financial Statements.
- Upon the expiration of the lease term, TEP purchased an undivided ownership interest in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million. In May 2015, SRP purchased from TEP a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million. With the completion of TEP's purchase, Tri-State does not have an obligation to purchase the facilities, but by April 2016 Tri-State must elect 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 Factors Affecting Results of Operations, Springerville Coal Handling Facilities Capital Lease Purchase and Note 4 to the Condensed Consolidated Financial Statements.
- See Note 5 to the Condensed Consolidated Financial Statements for long-term commitments entered into by TEP through September 30, 2015.

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

- 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, based on changes in contract values, a change in TEP’s credit ratings, or if there has been a material change in TEP’s creditworthiness. At September 30, 2015, TEP had posted $1 million in LOCs as collateral with wholesale counterparties for credit enhancement. As of November 5, 2015, TEP had no LOCs posted as collateral with wholesale counterparties for credit enhancement.
- We do not have any provisions in any of our debt or lease agreements that would cause an event of default or cause amounts to become due and payable in the event of a credit rating downgrade.

Income Tax Position

The 2010 Federal Tax Relief Act, the American Taxpayer Relief Act of 2012, and the Tax Increase Prevention Act of 2014 include provisions that make qualified property placed in service between 2010 and 2014 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 did not pay any federal or state income taxes the first nine months of 2015 and does not expect to make any payments until 2019.

Contribution from Parent

In June 2015, UNS Energy made an equity contribution of $180 million to TEP. A portion of the contribution was used to repay revolving credit loans and redeem bonds.

Dividend Paid

TEP paid a $25 million dividend to UNS Energy in the first nine months of 2015 and no dividend in the first nine months of 2014.

TEP can pay dividends if it maintains compliance with these restrictions as well as those of the Merger. The ACC order approving the Merger includes a stipulation limiting dividend payments to less than 60 percent of TEP's net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital. At September 30, 2015, TEP's equity ratio was slightly below 50 percent.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Management's Discussion and Analysis of Financial Condition and Results of Operations is based on our Condensed Consolidated Financial Statements, which have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The preparation of these financial statements requires management to make estimates, judgments and

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assumptions that affect the reported amounts of assets, liabilities, net revenues and expenses, and disclosure of contingent liabilities. Our management believes that there have been no significant changes during the nine months ended September 30, 2015, to the items that we disclosed as our critical accounting policies and estimates in Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2014 Annual Report on Form 10-K.

ACCOUNTING PRONOUNCEMENTS

For a summary of recent accounting pronouncements applicable to our financial statements see Note 9 to the Condensed Consolidated Financial Statements in Part I, Item 1.

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 can 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 2014 Annual Report on Form 10-K.

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 13(a) – 15(e) or Rule 15(d) – 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 as of September 30, 2015.

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 2015 that has materially affected, or is reasonably likely to materially affect, TEP’s internal control over financial reporting.

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PART II

ITEM 1. LEGAL PROCEEDINGS

For a description of certain legal proceedings affecting TEP, refer to Note 5 of the Condensed Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q.

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 2014 Annual Report on Form 10-K.

ITEM 5. OTHER INFORMATION

RATIO OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30, 2015	Twelve Months Ended September 30, 2015
Ratio of Earnings to Fixed Charges	4.168	3.435

For purposes of this computation, earnings are defined as pre-tax earnings from continuing operations before minority interest, or income/loss from equity method investments, plus interest expense and amortization of debt discount and expense related to indebtedness. Fixed charges are interest expense, including amortization of debt discount and expense, interest on operating lease payments, and expense on indebtedness, including capital lease obligations.

ENVIRONMENTAL MATTERS

Environmental Regulation

The EPA regulates the amount of sulfur dioxide (SO_2), nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury and other by-products produced 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.

National Ambient Air Quality Standards

On October 1, 2015, the EPA released the final rule for the 8-hour Ozone NAAQS or Ozone Standard. The EPA lowered the standard from 75 parts per billion (ppb) to 70ppb. TEP does not expect a material impact at any of its generating stations. At this point, it appears that Pima County may comply with the new standard. If Pima County does not meet the standard, it will be designated as a “non-attainment” area and will need to develop a plan to bring the air-shed into compliance. A “non-attainment” designation may slow economic growth in the region and impact our ability to site new generation.

Implementation of the rule is scheduled as follows:

- States’ recommendation of area designations (attainment, non-attainment, or unclassified) by October 2016.
- EPA's response to states’ designation recommendation by June 2017.
- EPA's finalization of area designations by October 2017, based on 2014-2016 air quality data.

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 Mercury and Air Toxics Standards (MATS) rules to set the standards for the control of mercury emissions and other hazardous air pollutants from power plants. Based on the rules, additional emission control equipment would have been required by April 2015. TEP, as operator of Springerville and Sundt, and the operators of Navajo Generating Station (Navajo) and Four Corners Generating Station (Four Corners) received extensions until April 2016 to comply with the MATS rules.

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In June 2015, the U.S. Supreme Court reversed and remanded the DC Circuit Court of Appeals decision to uphold the MATS rule requiring power plants to control mercury and other emissions. The Supreme Court held that the EPA did not adequately consider “cost” before determining that MATS is “appropriate and necessary”.

At this time, despite the U.S. Supreme Court ruling, the MATS rules remain in force and effect. TEP will proceed with its planned MATS compliance activity at each of our facilities. Additionally, Arizona has an Arizona-specific mercury rule in place that would become effective and applicable to our Arizona facilities in the event the Federal rule is struck down. Our compliance strategy ensures compliance with both the Federal and the State rule, as applicable.

For more information see Note 5 to the Condensed Consolidated Financial Statements.

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. 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.

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 Navajo, San Juan, and Four Corners 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.

For more information see Note 5 to the Condensed Consolidated Financial Statements.

Navajo

In August 2014, the EPA published the final Regional Haze Federal Implementation Plan (FIP) for Navajo. 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 Selective Catalytic Reduction (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. The final BART rule includes options that accommodate potential ownership changes at the plant. The plant has until December 2019 to notify the EPA of how it will comply with the FIP. If SCR technology is ultimately implemented at Navajo, TEP estimates its share of the capital cost will be $28 million for the two remaining units.

San Juan

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) covering BART requirements for San Juan. The SIP requires 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 February of 2016. TEP owns 50% of Units 1 and 2 at San Juan. Prior to the shutdown of any units at San Juan, PNM, the operator, must first obtain New Mexico Public Regulation Commission approval. TEP expects its share of the cost to install SNCR technology on San Juan Unit 1 to be approximately $12 million. Additionally, the SIP approval references a New Source Review permit issued by the New Mexico Environment Department in November 2013 which, among other things, calls for balanced draft upgrades on San Juan Unit 1 to reduce particulate matter emissions. Public Service Company of New Mexico (PNM), the operator of San Juan, is currently installing SNCR and balanced draft modifications to San Juan Unit 1 were completed in June 2015. TEP’s share of the balanced draft upgrades was approximately $22 million. TEP's share of incremental annual operating costs for SNCR for San Juan Unit 1 is estimated at $1 million.

In connection with the implementation of the SIP revision and the early 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 have negotiated 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 engaged a mediator to assist in facilitating the resolution of these matters among the Participants. The Participants 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.

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At September 30, 2015, the NBV of TEP's share in San Juan Unit 2, including construction work in progress, was $105 million. Consistent with the 2013 Rate Order, TEP has requested to apply excess depreciation reserves against the unrecovered NBV in its 2015 Rate Case.

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, Arizona Public Service Company (APS), the operator of Four Corners, decided to exercise an option 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 $44 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 June 2014, the EPA issued a final Regional Haze FIP for Arizona including BART requirements for Sundt. The final FIP 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 $6 million. Under the rule, TEP is required to notify the EPA of its decision by March 2017. We expect to make a decision by early 2016 as part of our MATS compliance plan for Sundt. At September 30, 2015, the NBV of the Sundt coal handling facilities was $16 million. In August 2015, TEP exhausted its existing coal supply at Sundt and has been operating Sundt with natural gas as a primary fuel source. TEP expects to retire the Sundt coal handling facilities earlier than expected, and has requested to apply excess depreciation reserves against the unrecovered NBV in its 2015 Rate Case. The estimated NO_x emissions control costs will not be expended if Sundt is retired early.

Greenhouse Gas Regulation

In August 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled power plants. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets CO_2 emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States are required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that receive an extension must submit a final completed plan to the EPA by September 2018. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.

The EPA incorporated the compliance obligations for existing power plants located on Indian nations, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian nation and/or state that does not submit a plan or that does not have an EPA or approved state plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP plans to comment on the proposed Federal Plan impacting our facilities, including Four Corners and Navajo. TEP cannot predict the ultimate outcome of these matters.

TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not own or operate any impoundments. Under the rule, the Springerville Generating Station (Springerville) ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP’s share of the cost at Springerville is estimated to be $2 million, the majority of which is

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expected to be capital expenditures. TEP currently estimates its share of the costs to be $4 million at Four Corners, $1 million at Navajo, and less than $1 million at San Juan, the majority of which are expected to be capital expenditures.

Effluent Limitation Guidelines

In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines setting technology standards and limitations for steam electric power plant discharges. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. TEP is evaluating the effects of this rule on its facilities including Navajo, San Juan, and Four Corners. Since the majority of TEP's facilities are zero discharge, TEP does not anticipate a significant financial impact.

For more information see Note 5 to the Condensed Consolidated Financial Statements.

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 6, 2015	/s/ Kevin P. Larson Kevin P. Larson Senior Vice President and Chief Financial Officer

EXHIBIT INDEX

3	—	Bylaws of TEP, as amended as of August 12, 2015
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.