TUCSON ELECTRIC POWER CO
Form 10-K
February 19, 2015

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 1-5924
TUCSON ELECTRIC POWER COMPANY
(Exact name of registrant as specified in its charter)

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

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

Securities registered pursuant to Section 12(b) of the Exchange Act: None
Securities registered pursuant to Section 12(g) of the Exchange Act:

Common Stock, without par value
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

Yes ¨ No x

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of each registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates: None
As of 01/30/15, Tucson Electric Power Company had 32,139,434 shares of common stock, no par value, outstanding, all of which were held by UNS Energy Corporation.

Documents incorporated by reference: None

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DEFINITIONS

The abbreviations and acronyms used in the 2014 Form 10-K are defined below:

2010 Credit Agreement	The 2010 Credit Agreement consists of a $200 million revolving credit and LOC facility together with an $82 million LOC facility to support tax-exempt bonds
2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Covenants Agreement	A Lender Rate Mode Covenants Agreement between TEP and the purchaser of $100 million of unsecured tax-exempt bonds that were issued on behalf of TEP in November 2013 and sold in a private placement
2013 TEP Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
2014 Credit Agreement	The 2014 Credit Agreement consists of a $130 million term loan commitment and a $70 million revolving credit commitment
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
Base O&M	A non-GAAP financial measure that represents the fundamental level of operating and maintenance expense related to our business
Base Rates	The portion of TEP’s Retail Rates attributed to generation, transmission, distribution, and customer costs. Base Rates exclude authorized charges designed to recover specific costs that are passed through to customers including fuel and purchased energy costs, energy efficiency program costs, certain environmental compliance costs, and a portion of renewable energy costs
Btu	British thermal unit(s)
Cooling Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting 75 from the average of the high and low daily temperatures
DG	Distributed Generation
DSM	Demand Side Management
ECA	Environmental Compliance Adjustor
EE	Energy Efficiency
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
GAAP	Generally Accepted Accounting Principles in the United States
GBtu	Billion British thermal units
GWh	Gigawatt-hour(s)
Gila River Unit 3	Unit 3 of the Gila River Generating Station
Heating Degree Days	An index used to measure the impact of weather on energy usage calculated by subtracting the average of the high and low daily temperatures from 65
kV	Kilo-volt(s)
kWh	Kilowatt-hour(s)
LFCR	Lost Fixed Cost Recovery
LOC	Letter of Credit
Merger	The acquisition of UNS Energy in 2014 pursuant to the Agreement and Plan of Merger between UNS Energy 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

PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
ppb	Parts per billion
REC	Renewable Energy Credit
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas
RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
Springerville Coal Handling Facilities	Coal handling facilities at Springerville used by all four Springerville units
Springerville Coal Handling Facilities Leases	Leases for coal handling facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities	Facilities at Springerville used in common by all four Springerville units
Springerville Common Facilities Leases	Leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 1	Unit 1 of the Springerville Generating Station
Springerville Unit 1 Leases	Leveraged lease arrangement relating to Springerville Unit 1 and an undivided one-half interest in certain Springerville Common Facilities
Springerville Unit 2	Unit 2 of the Springerville Generating Station
Springerville Unit 3	Unit 3 of the Springerville Generating Station
Springerville Unit 4	Unit 4 of the Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	H. Wilson Sundt Generating Station
Sundt Unit 4	Unit 4 of the H. Wilson Sundt Generating Station
TEP	Tucson Electric Power Company, the principal subsidiary of UNS Energy Corporation
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) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
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, the parent company of TEP, whose principal executive offices are located at 88 East Broadway Boulevard, Tucson, Arizona 85701
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

FORWARD-LOOKING INFORMATION

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

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s expectations, beliefs or projections will be achieved or accomplished. We have identified the following important factors that could cause actual results to differ materially from those discussed in our forward-looking statements. These may be in addition to other factors and matters discussed in: Part I, Item 1A. Risk Factors; Part II, Item 7. 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. BUSINESS

GENERAL

Tucson Electric Power Company (TEP) is a vertically integrated, regulated utility that generates, transmits and distributes electricity. 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 the largest investor-owned gas and electric distribution utility holding company in Canada.

FORTIS ACQUISITION OF UNS ENERGY

UNS Energy, the parent of TEP, was acquired by Fortis for $60.25 per share of UNS Energy common stock in cash effective August 15, 2014.

The Arizona Corporation Commission's (ACC) approval of the Merger was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling approximately $19 million over five years: $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital; and
- Fortis making an equity investment of at least $220 million to UNS Energy and its regulated subsidiaries, including TEP. Fortis exceeded the investment requirement by contributing $287 million to UNS Energy through December 31, 2014. UNS Energy then contributed a total of $225 million to TEP through December 31, 2014.

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

SERVICE AREA AND CUSTOMERS

TEP’s service territory covers 1,155 square miles with service to approximately 415,000 retail electric customers and includes a population of approximately one million people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.

Retail Customers

TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases, and other governmental entities. TEP’s retail sales are influenced by several factors, including economic conditions, seasonal weather patterns, Demand Side Management (DSM) initiatives and the increasing use of energy efficient products, and opportunities for customers to generate their own electricity.

Customer Base

The table below shows the percentage distribution of TEP’s energy sales by major customer class over the last three years. In 2015, the retail energy consumption by customer class is expected to be similar to the historical distribution.

	2014		2013		2012	
Residential	41	%	42	%	41	%
Commercial	24	%	23	%	24	%
Non-mining Industrial	23	%	23	%	23	%
Mining	12	%	12	%	12	%

Local, regional, and national economic factors can impact the growth in the number of customers in TEP's service territory. In 2014, 2013, and 2012, TEP's average number of retail customers increased by less than 1% in each year. We expect the number of TEP's retail customers to increase at a rate of approximately 1% in 2015 and 2016 based on estimated population growth in our service territory.

Two of TEP's largest retail customers are in the copper mining industry. TEP's kilowatt-hour (kWh) sales to mining customers depend on a variety of factors including the market price of copper, the electricity rate paid by mining customers, and the mines' potential development of their own electric generation resources. TEP's kWh sales to mining customers increased by 5.4% in 2014.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Sales to Mining Customers.

Retail Sales Volumes

TEP's retail sales volumes in 2014 were approximately 9,165 Gigawatt-hours (GWh). These volumes were 1.3% below 2010 levels. During the past four years, economic conditions and state requirements for Energy Efficiency (EE) and Distributed Generation (DG) have negatively affected retail electricity sales.

Wholesale Sales

TEP's electric utility operations include the wholesale marketing of electricity to other utilities and power marketers. Wholesale sales transactions are made on both a firm and interruptible basis. A firm contract requires TEP to supply power on demand (except under limited emergency circumstances), while an interruptible contract allows TEP to stop supplying power under defined conditions. See Generating and Other Resources, Purchases and Interconnections, below.

Generally, TEP commits to future sales based on expected excess generating capability, forward prices, and generation costs, using a diversified portfolio approach to provide a balance between long-term, mid-term, and spot energy sales. TEP's wholesale sales consist primarily of two types of sales:

Long-Term Sales

Long-term wholesale sales contracts cover periods of more than one year. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers. In 2014, TEP's two primary long-term contracts were with Salt River Project Agriculture Improvement and Power District (SRP) and the Navajo Tribal Utility Authority (NTUA). The SRP contract expires in May 2016 and the NTUA contract expires in December 2022.

In December 2014, TEP entered into two additional long-term wholesale sales contracts that began in January 2015. The first long-term sales contract is with TRICO Electric Cooperative and expires in December 2024. The second long-term sales contract is with Shell Energy North America and expires in December 2017. The execution of these two additional wholesale sales contracts use near-term capacity acquired with TEP's purchase of Gila River Unit 3 discussed below.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Long-Term Wholesale Sales.

Short-Term Sales

Forward contracts commit TEP to sell a specified amount of capacity or energy at a specified price over a given period of time, typically for one-month, three-month, or one-year periods. TEP also engages in short-term sales by selling energy in the daily or hourly markets at fluctuating spot market prices and making other non-firm energy sales. All revenues from short-term wholesale sales offset fuel and purchased power costs and are passed through to TEP's retail customers. TEP uses short-term wholesale sales as part of its hedging strategy to reduce customer exposure to fluctuating power prices. See Rates and Regulation, below.

GENERATING AND OTHER RESOURCES

As of January 1, 2015, following completion of the purchase of a 24.8% leased interest in Springerville Unit 1 and expiration of the Springerville Unit 1 leases, TEP owned 2,448 MW of nominal generating capacity, as set forth in the following table. Nominal capacity is based on unit design net output.

Generating Source	Unit No.	Location	Date In Service	Resource Type	Capacity MW	Operating Agent	TEP's Share %	TEP's Share MW
Springerville Station[(1)]	1	Springerville, AZ	1985	Coal	387	TEP	49.5	192
Springerville Station	2	Springerville, AZ	1990	Coal	390	TEP	100.0	390
San Juan Station	1	Farmington, NM	1976	Coal	340	PNM	50.0	170
San Juan Station	2	Farmington, NM	1973	Coal	340	PNM	50.0	170
Navajo Station	1	Page, AZ	1974	Coal	750	SRP	7.5	56
Navajo Station	2	Page, AZ	1975	Coal	750	SRP	7.5	56
Navajo Station	3	Page, AZ	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	Farmington, NM	1969	Coal	785	APS	7.0	55
Four Corners Station	5	Farmington, NM	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	Gila Bend, AZ	2003	Gas	550	Ethos Energy	75.0	413
Luna Generating Station	1	Deming, NM	2006	Gas	555	PNM	33.3	185
Sundt Station	1	Tucson, AZ	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	Tucson, AZ	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station [(2)]	4	Tucson, AZ	1967	Coal	120	TEP	100.0	120
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100.0	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100.0	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	12	TEP	100.0	12
Ft. Huachuca Project		Ft. Huachuca, AZ	2014	Solar	17	TEP	100.0	17
Total TEP Capacity [(3)]								2,448

(1) At December 31, 2014, TEP owned 96 MW of capacity at Springerville Unit 1 and continued to lease the remaining 291 MW of capacity. In January 2015, TEP purchased 96 MW of capacity bringing the total owned capacity to 192 MW. TEP's lease of the remaining 195 MW expired in January 2015. See Note 5 of Notes to Consolidated Financial Statements.

(2) Sundt Station Unit 4 can be operated on either coal or natural gas. The table above reflects the nominal generating capacity assuming the unit is fueled by coal. If the Unit burns natural gas, it has a nominal capacity of 156 MW.

(3) Excludes 932 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.

Springerville Generating Station

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 and included fair market value renewal and purchase options. As of January 1, TEP owns 49.5% of Unit 1 and a one-quarter interest in the common facilities.

In 2006, TEP purchased a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 megawatts (MW) of capacity. During 2013, TEP agreed to purchase leased interests of 35.4% or 137 MW of Springerville Unit 1, for an aggregate purchase price of approximately $65 million. TEP completed the purchase of a 10.6% leased interest, representing 41 MW of capacity in December 2014 and a 24.8% leased interest, representing 96

MW of capacity, in January 2015. The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, continues to be owned by third parties, i.e.

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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). With the expiration of the leases in January 2015, TEP is obligated to operate the unit for the Third-Party Owners under an existing facility support agreement. The Third-Party Owners are obligated to compensate TEP for their pro rata share of expenses for the unit in the amount of approximately $1.5 million per month, and their share of capital expenditures, which are approximately $7 million in 2015.

See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Springerville Unit 1.

Springerville Unit 2

Unit 2 of the Springerville Generating Station (Springerville Unit 2) is owned by San Carlos Resources, Inc. (San Carlos), a wholly-owned subsidiary of TEP.

Springerville Common Facilities Leases

The leveraged lease arrangements relating to an undivided one-half interest in certain Springerville Common Facilities (Springerville Common Facilities Leases), which expire in 2017 and 2021, have fair market value renewal options as well as fixed-price purchase options. The fixed prices to acquire the leased interests in the Springerville Common Facilities are $38 million in 2017 and $68 million in 2021.

Springerville Coal Handling Facilities Lease

In 1984, TEP sold and leased back the Springerville Coal Handling Facilities. Since entering into the lease, TEP purchased a 13% ownership interest in the Springerville Coal Handling Facilities. The terms of the Springerville Coal Handling Facilities Leases expire in April 2015 but have fixed-rate renewal options if certain conditions are satisfied as well as a fixed-price purchase provision of $120 million. In April 2014, TEP notified the owner participants and their lessors that TEP has elected to purchase their undivided ownership interests in the facilities at the fixed purchase price of $120 million upon the expiration of the lease term in April 2015. Upon TEP’s purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million and Tri-State Generation and Transmission Association, Inc. (Tri-State) is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities.

See Note 5 of Notes to Consolidated Financial Statements and Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Contractual Obligations.

Sundt Generating Station

The H. Wilson Sundt Generating Station (Sundt) and the internal combustion turbines located in Tucson are designated as “must-run generation” facilities. Must-run generation units are required to run in certain circumstances to maintain distribution system reliability and to meet local load requirements.

Gila River Generating Station Unit 3

On December 10, 2014, TEP and UNS Electric, Inc. (UNS Electric), an affiliated subsidiary of UNS Energy, acquired Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW located in Gila Bend, Arizona, from a subsidiary of Entegra Power Group LLC. TEP purchased a 75% undivided interest in Gila River Unit 3 (413 MW) for $164 million, and UNS Electric purchased the remaining 25% undivided interest. See Item 7. Management's Discussion and Analysis of Financial Condition and Factors Affecting Results of Operations, Gila River Generating Station Unit 3 and Note 7 of Notes to Consolidated Financial Statements.

The purchase of Gila River Unit 3 is intended to replace the expired coal-fired leased capacity from Springerville Unit 1 and the expected reduction of coal-fired generating capacity from San Juan Unit 2, and is consistent with TEP's strategy to diversify its generation fuel mix. See Environmental Matters, Regional Haze Rules, San Juan, below.

Renewable Energy Resources

Owned Resources

As of December 31, 2014, TEP owned 45 MW of photovoltaic (PV) solar generating capacity. The Springerville solar system, which is located near the Springerville Generating Station, has a total capacity of 16 MW, including 10 MW of capacity

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completed in December 2014. In December 2014, TEP also completed a solar project providing 17 MW of capacity at Ft. Huachuca, Arizona. TEP's remaining 12 MW of PV solar generating capacity is located in the Tucson area.

Power Purchase Agreements

In order to meet the ACC's renewable energy requirements, TEP has power purchase agreements (PPAs) for 145 MW of capacity from solar resources, 90 MW of capacity from wind resources and 4 MW of capacity from a landfill gas generation plant. At December 31, 2014, approximately 124 MW of contracted solar resources and 50 MW of contracted wind resources were operational. The remaining resources are expected to be developed over the next several years. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future period. See Rates and Regulation, Renewable Energy Standard and Tariff, below.

Power Purchases

TEP purchases power from other utilities and power marketers. TEP may enter into contracts: (a) to purchase energy under long-term contracts to serve retail load and long-term wholesale contracts, (b) to purchase capacity or energy during periods of planned outages or for peak summer load conditions, and (c) to purchase energy for resale to certain wholesale customers under load and resource management agreements.

TEP typically uses generation from its gas-fired units, supplemented by power purchases, to meet the summer peak demands of its retail customers. Some of these power purchases are price-indexed to natural gas. Due to its increasing seasonal gas and purchased power usage, TEP hedges a portion of its total natural gas exposure with fixed price contracts for a maximum of three years. TEP also purchases energy in the daily and hourly markets to meet higher than anticipated demands, to cover unplanned generation outages, or when doing so is more economical than generating its own energy.

TEP is a member of a regional reserve-sharing organization and has reliability and power sharing relationships with other utilities. These relationships allow TEP to call upon other utilities during emergencies, such as plant outages and system disturbances, and reduce the amount of reserves TEP is required to carry.

Springerville Units 3 and 4

Springerville Units 3 and 4 are each approximately 400 MW coal-fired generating facilities that are operated, but not owned by TEP. These facilities are located at the same site as Springerville Units 1 and 2. The owners of Springerville Units 3 and 4 compensate TEP for operating the facilities and pay an allocated portion of the fixed costs related to the Springerville Common Facilities and Coal Handling Facilities. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Springerville Units 3 and 4.

Peak Demand and Resources

Peak Demand	2014 MW	2013	2012	2011	2010
Retail Customers	2,218	2,230	2,290	2,334	2,333
Firm Sales to Other Utilities	673	484	286	322	340
Coincident Peak Demand (A)	2,891	2,714	2,576	2,656	2,673
Total Generating Resources	2,240	2,240	2,267	2,262	2,245
Other Resources [1]	932	775	683	1,009	799
Total TEP Resources (B)	3,172	3,015	2,950	3,271	3,044
Total Margin (B) – (A)	281	301	374	615	371
Reserve Margin (% of Coincident Peak Demand)	10 %	11 %	15 %	23 %	14 %

(1) Other Resources include firm power purchases and interruptible retail and wholesale loads.

The chart above shows the relationship over a five-year period between peak demand and energy resources. Total margin is the difference between total energy resources and coincident peak demand, and the reserve margin is the ratio of margin to coincident peak demand. The reserve margin in 2014 was in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of NERC.

Peak demand occurs during the summer months due to the cooling requirements of retail customers. Retail peak demand varies from year-to-year due to weather, economic conditions, and other factors. Retail peak demand declined over the period of 2010

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to 2014 due primarily to weak economic conditions and the implementation of energy efficiency programs and distributed generation.

Forecasted retail peak demand for 2015 is 2,222 MW compared with actual peak demand of 2,218 MW in 2014. TEP's 2015 estimated retail peak demand is based on weather patterns observed over a 10-year period and other factors, including estimates of customer usage. TEP believes existing generation capacity and PPAs are sufficient to meet expected demand in 2015 and established reserve margin criteria.

FUEL SUPPLY

Fuel and Purchased Power Summary

Resource information is provided below:

	Average Cost per kWh (cents per kWh)			Percentage of Total kWh Resources					
	2014	2013	2012	2014		2013		2012	
Coal	2.50	2.66	2.54	68	%	75	%	72	%
Gas	4.99	4.57	4.54	9	%	8	%	11	%
Purchased Power	4.79	4.83	3.44	23	%	17	%	17	%
All Sources	3.64	3.54	3.19	100	%	100	%	100	%

Coal

TEP's principal fuel for electric generation is low-sulfur, bituminous or sub-bituminous coal from mines in Arizona and New Mexico. The table below provides information on the existing coal contracts that supply our generating stations. The average cost per ton of coal, including transportation, was $45.50 in 2014, $48.51 in 2013, and $45.84 in 2012.

Station	Coal Supplier	2014 Coal Consumption (tons in 000s)	Contract Expiration	Avg. Sulfur Content	Coal Obtained From
Springerville	Peabody CoalSales	2,868	2020	0.9%	Lee Ranch Coal Co.
Four Corners[1]	BHP Billiton	344	2031	0.7%	Navajo Indian Tribe
San Juan	San Juan Coal Co.	1,146	2017	0.8%	Federal and State Agencies
Navajo	Peabody CoalSales	591	2019	0.6%	Navajo and Hopi Indian Tribes

(1) Beginning in July 2016 through June 2031, the coal for Four Corners will be purchased from the Navajo Transitional Energy Company (NTEC). NTEC purchased the mine located near Four Corners from BHP Billiton and will begin operating the mine in 2016.

TEP Operated Generating Facilities

The coal supplies for Springerville Units 1 and 2 are transported approximately 200 miles by railroad from northwestern New Mexico. TEP expects coal reserves to be sufficient to supply the estimated requirements for Springerville Units 1 and 2 for their presently estimated remaining lives.

TEP does not have a long-term coal supply contract for Sundt Unit 4. Prior to 2010, Sundt Unit 4 was predominantly fueled by coal; however, the generating station also can be operated with natural gas. Both fuels are combined with landfill gas, a renewable energy resource, delivered from a nearby landfill. Since 2010, TEP has fueled Sundt Unit 4 with both coal and natural gas depending on which resource is most economic. See Note 6 of Notes to Consolidated Financial Statements.

Coal Generating Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generating facilities at the Four Corners Generating Station (Four Corners), the Navajo Generating Station (Navajo), and the San Juan Generating Station (San Juan). Four Corners, which is operated by Arizona Public Service Company (APS), and San Juan, which is operated by Public Service Company of New Mexico (PNM), are mine-mouth generating stations located adjacent to the coal reserves. Navajo, which is operated by SRP, obtains its coal supply from a nearby coal mine and a dedicated rail delivery system. The coal supplies are received under contracts administered by the operating agents. As indicated in the table above, the current coal supply contract for San Juan expires on December 31, 2017. TEP and other San Juan owners are currently negotiating agreements concerning the future San Juan fuel supply with the existing coal supplier. If the participants are unable to negotiate an economic fuel supply, the continued operation of San Juan could be adversely affected.

Natural Gas Supply

TEP typically uses generation from its facilities fueled by natural gas, in addition to energy from its coal-fired facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. TEP purchases gas from Southwest Gas Corporation under a retail tariff for North Loop’s 94 MW of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie, a 75 MW internal combustion turbine. TEP purchases capacity from El Paso Natural Gas (EPNG) for transportation from the San Juan and Permian Basins to its Sundt plant under firm transportation agreements and buys gas from third-party suppliers for Sundt and DeMoss Petrie.

TEP also purchases firm gas transportation for Gila from EPNG and Transwestern and for Luna Generating Station (Luna) from EPNG.

TRANSMISSION ACCESS

TEP has transmission access and power transaction arrangements with over 140 electric systems or suppliers. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability, capacity and efficiency of its existing transmission and distribution systems.

To improve transmission capacity between Palo Verde and Tucson, TEP participated in the construction and ownership of a 500 kV transmission line from the Palo Verde area to the Pinal Central substation east of Casa Grande, AZ. This project was placed in service in 2014. Also, construction is underway on a 45-mile 500-kV transmission line from the Pinal Central substation to TEP’s Tortolita substation northwest of Tucson. TEP expects the Pinal Central to Tortolita line to be in service in 2016. Additionally, TEP is working with SRP and others to tie the Gila River power plant into TEP’s Palo Verde to Tucson transmission system. This will provide an improved electrical path to bring Gila River Unit 3 power into Tucson.

As part of TEP’s purchase of the Gila River unit TEP received transmission rights across the APS transmission system. These rights extend from the Gila River switchyard adjacent to the plant to the Jojoba switchyard. TEP is pursuing interconnection of the Jojoba switchyard to the existing transmission line from the Palo Verde area to Pinal Central substation in which TEP has an ownership interest. This interconnection, along with the rights obtained with the purchase, will provide direct transmission access from the Gila Plant to TEP’s service territory.

Discontinued Transmission Project

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

RATES AND REGULATION

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

2013 TEP Rate Order

In June 2013, the ACC issued an order (2013 TEP Rate Order) which was based on a test year ended December 31, 2011. The 2013 TEP Rate Order approved new rates effective July 1, 2013. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, 2013 TEP Rate Order.

Purchased Power and Fuel Adjustment Clause

The Purchased Power and Fuel Adjustment Clause (PPFAC) allows TEP to recover its fuel, transmission, and purchased power costs, including demand charges, and the costs of contracts for hedging fuel and purchased power costs for its retail customers. The PPFAC consists of a forward component and a true-up component.

The true-up component will reconcile any over/under collected amounts from the preceding 12-month period and will be credited to or recovered from customers in the subsequent year.

TEP’s PPFAC also includes the recovery of the following costs and/or credits: lime costs used to control SO2 emissions at Springerville, sulfur credits received from TEP’s coal suppliers; broker fees; 100% of short-term wholesale revenues; and all of the proceeds from the sale of SO2 allowances.

At December 31, 2014, TEP had under-collected fuel and purchased power costs on a billed-to-customer basis of $32 million.

Renewable Energy Standard and Tariff

The ACC’s Renewable Energy Standard (RES) requires TEP and other affected utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. Affected utilities must file annual RES implementation plans for review and approval by the ACC. The approved cost of carrying out those plans is recovered from retail customers through the RES surcharge until such costs are reflected in TEP’s Base Rates.

In December 2014, the ACC approved TEP's 2015 RES implementation plan. Under the plan, TEP expects to collect approximately $33 million from retail customers during 2015 to fund the following: the above market cost of renewable energy purchases; performance based incentives for customer installed DG; depreciation and a return on TEP's investments in company-owned solar projects; and various other program costs. TEP expects to recognize approximately $4 million of revenue in 2015 as a return on company-owned solar projects.

The 2015 RES implementation plan authorized a TEP investment of $10 million in 2015 for up to 600 company-owned residential solar projects. Participants in this program will take service under a fixed electric rate. While participating customers could realize significant savings over time if TEP's standard rates or energy costs increase, their payments are expected to cover a majority of the company's fixed service costs associated with that customer.

TEP met the overall 2014 RES renewable energy target of 4.5% of retail kWh sales and expects to meet the 2015 target of 5% of retail kWh sales. Compliance with RES is determined through periodic filings with the ACC. As TEP no longer pays incentives to obtain distributed generation Renewable Energy Credits (REC), which are used to demonstrate compliance with the distributed generation requirement, the company may request a waiver of the RES distributed generation requirements.

Electric Energy Efficiency Standards

In 2010, the ACC approved new Electric EE Standards designed to require electric utilities to implement cost-effective programs to reduce customers' energy consumption. The Electric EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. Since the implementation of the Electric EE Standards, TEP’s cumulative annual energy savings are approximately 7.0% of retail kWh sales. TEP’s compliance with the Electric EE Standards is governed by the ACC’s approval of implementation plans filed by TEP annually.

In December 2014, the ACC approved TEP’s 2014 and 2015 Energy Efficiency Implementation Plans. Under the 2015 plan, TEP expects to collect approximately $19 million from retail customers and will offer customers new and existing DSM programs. Energy savings realized through the programs will count toward Arizona’s Energy Efficiency Standard and the associated lost revenue will be partially collected through the Lost Fixed Cost Recovery Mechanism (LFCR). See Note 2 of Notes to Consolidated Financial Statements. In December 2014, the ACC initiated a new rulemaking proceeding that could result in the elimination of specific targeted savings and instead treat EE as a resource to be evaluated through the ACC's integrated resource planning process.

TEP'S UTILITY OPERATING STATISTICS					
	2014	2013	2012	2011	2010
Generation and Purchased Power – kWh (000)					
Remote Generation	9,616,347	10,586,972	10,284,612	10,005,127	9,077,032
Local Tucson Generation	864,949	674,443	803,146	906,496	1,492,885
Renewable Generation	48,434	38,206	44,930	28,049	24,511
Purchased Power	3,195,173	2,328,581	2,328,420	2,686,918	2,846,005
Total Generation and Purchased Power	13,724,903	13,628,202	13,461,108	13,626,590	13,440,433
Less Losses and Company Use	859,638	885,026	789,613	822,220	879,423
Total Energy Sold	12,865,265	12,743,176	12,671,495	12,804,370	12,561,010
Sales – kWh (000)					
Residential	3,726,982	3,866,665	3,820,637	3,888,011	3,869,540
Commercial	2,169,897	2,187,095	2,187,617	2,184,241	2,171,694
Industrial	2,098,229	2,113,659	2,132,214	2,145,163	2,138,749
Mining	1,137,188	1,079,150	1,092,518	1,083,071	1,079,327
Other	33,057	32,350	31,833	31,621	32,478
Total – Electric Retail Sales	9,165,353	9,278,919	9,264,819	9,332,107	9,291,788
Electric Wholesale Sales- Long-Term	617,502	605,426	657,740	902,139	987,957
Electric Wholesale Sales- Short-Term	3,082,410	2,858,831	2,748,936	2,570,124	2,281,265
Total Electric Sales	12,865,265	12,743,176	12,671,495	12,804,370	12,561,010
Operating Revenues ($000)					
Residential	$409,964	$400,999	$387,840	$383,908	$372,212
Commercial	261,813	252,547	247,157	241,044	233,567
Industrial	170,436	164,433	166,739	164,024	159,937
Mining	70,110	65,094	66,158	65,720	62,112
Other	2,985	2,809	2,693	2,601	2,593
RES, DSM, ECA and LFCR	54,837	48,475	45,292	46,633	37,767
Total – Electric Retail Sales	970,145	934,357	915,879	903,930	868,188
Wholesale Revenue- Long-Term	28,216	26,203	24,910	41,056	55,653
Wholesale Revenue- Short-Term	113,575	91,467	71,257	72,798	71,435
California Power Exchange Provision for Wholesale Refunds	—	—	—	—	(2,970)
Transmission	16,532	14,830	15,793	16,392	20,863
Other Revenues	141,433	129,833	133,821	122,210	112,098
Total Operating Revenues	$1,269,901	$1,196,690	$1,161,660	$1,156,386	$1,125,267
Customers (End of Period)					
Residential	374,204	372,411	369,480	367,396	366,217
Commercial	38,079	37,913	37,672	37,536	37,215
Industrial	604	617	632	636	635
Mining	4	4	4	4	4
Other	1,858	1,857	1,833	1,814	1,829
Total Retail Customers	414,749	412,802	409,621	407,386	405,900
Average Retail Revenue per kWh Sold (cents)					
Residential	11.0	10.4	10.2	9.9	9.6
Commercial	12.1	11.5	11.3	11.0	10.8
Industrial and Mining	7.4	7.2	7.2	7.1	6.9

Average Retail Revenue per kWh Sold (cents) (excludes RES, DSM, ECA and LFCR)	10.0	9.5	9.4	9.2	8.9
Average Revenue per Residential Customer	$1,096	$1,077	$1,050	$1,045	$1,016
Average kWh Sales per Residential Customer	9,960	10,383	10,341	10,583	10,566

ENVIRONMENTAL MATTERS

National Ambient Air Quality Standards

In November 2014, the EPA released a proposed rule that would revise the ozone National Ambient Air Quality Standards (NAAQS). The proposal revises the primary 8-hour NAAQS to within a range of 65-70 parts per billion (ppb), but the EPA is also taking comments on retaining the existing 75 ppb 8-hour standard or adopting an 8-hour standard as low as 60 ppb.

If the standard is ultimately revised below 70 ppb, Pima County and many other parts of the state would likely not be able to comply based on current ozone levels. Pima County and the State would then need to submit a plan to meet the revised standard which could potentially limit economic growth in the affected regions. TEP is currently analyzing the proposal and expects to file comments. The EPA is expected to finalize the rule by October 2015.

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.

Navajo

Based on the MATS rules, Navajo will require mercury control equipment by April 2016. TEP's share of the estimated capital costs of this equipment is less than $1 million for mercury control. TEP expects its share of the annual operating costs for mercury control to be less than $1 million.

San Juan

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

Four Corners

TEP expects Four Corners' current emission controls to be adequate to comply with the MATS rules.

Springerville Generating Station

Based on the MATS rules, Springerville Generating Station (Springerville) may require mercury emission control equipment by April 2016. The estimated capital cost of this equipment for Springerville Units 1 and 2 is about $5 million. TEP expects the annual operating cost of the mercury emission control equipment to be about $1 million. Estimated costs are split equally between the two units. TEP owns 49.5% of Springerville Unit 1 with the close of the lease option purchases in December 2014 and January 2015. With the completion of the purchases, Third-Party Owners are responsible for 50.5% of environmental costs attributed to Springerville Unit 1. TEP continues to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

Sundt Generating Station

TEP expects the MATS rules will have an immaterial impact on capital or operating expenses at Sundt.

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 the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in the units they own at these power plants. TEP cannot predict the ultimate outcome of these matters.

Navajo

In 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

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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 includes options that accommodate potential ownership changes at the plant. The plant has until December 2019 to notify the EPA which option will be implemented.

If SCR technology is ultimately implemented at Navajo, TEP estimates its share of the capital cost will be $28 million. Also, the installation of SCR technology at Navajo could increase the power plant's particulate emissions which may require that baghouses be installed. TEP estimates that its share of the capital expenditure for baghouses would be about $28 million. TEP's share of annual operating costs for SCR and baghouses is estimated at less than $1 million each.

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. 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. PNM, the operator of San Juan, is currently installing SNCR and making the necessary balanced draft modifications to San Juan Unit 1. TEP’s share of the balanced draft upgrades is expected to be approximately $25 million for a total of $37 million in capital expenditures. 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 are attempting to negotiate a restructuring of the ownership in San Juan, as well as addressing the obligations of the exiting Participants for plant decommissioning, mine reclamation, environmental matters, and certain ongoing operating costs, among other items. The Participants have engaged a mediator to assist in facilitating the resolution of these matters among the 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.

Upon the early retirement of San Juan Unit 2, TEP will seek ACC approval to recover any unrecovered cost. TEP's 2013 Rate Case identified an excess of required generation depreciation reserves. As stipulated in the 2013 Rate Order, TEP will seek the ACC's authority to apply any excess generation depreciation reserves to the unrecovered book value of any early retirement of generation assets prior to seeking additional recovery. TEP expects the excess generation depreciation reserves to fully cover the costs associated with early retirement of Unit 2. At December 31, 2014, the net book value of TEP's share in San Juan Unit 2 was $110 million.

Four Corners

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

Springerville

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

Sundt

In July 2013, the EPA rejected the Arizona SIP determination that Sundt Unit 4 is not subject to the BART provisions of the Regional Haze Rule and developed a time-line to issue a federal implementation plan for emissions sources including Sundt Unit 4. TEP submitted a better-than-BART proposal in November 2013 which called for the elimination of coal as a fuel source at Sundt by the end of 2017. In June 2014, the EPA issued a final 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 $5 million to $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 December 31, 2014, the net book value of the Sundt coal handling facilities was $17 million. If retired early, we will request the ACC's approval to recover all the remaining costs of the coal handling facilities.

Greenhouse Gas Regulation

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

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

In June 2014, the EPA issued proposed carbon emission regulations for existing power plants called the Clean Power Plan. The Clean Power Plan targets a nation-wide reduction in carbon emissions of 30% by 2030. To achieve this goal, the proposed plan sets carbon emission rates for each state that must be achieved by an interim period of 2020-2029, with final emission rates by 2030. States can apply a variety of strategies to achieve the interim and final emission rates. Using 2012 as a baseline year, Arizona's carbon emission rate for 2030 represents a 52% reduction, most of which would be required by the interim emission rate requirement and could lead to the early retirement of coal generation in Arizona by 2020. The EPA expects to issue a final rule by the summer of 2015, and under the current proposal, states must file implementation plans by June 2016 or June 2017 for multi-state plans. In October 2014, the EPA issued a supplemental proposal regarding carbon emissions regulation impacting the Navajo Nation and the Four Corners and Navajo generating stations which are located on land leased from the Navajo Nation. The regulation, if implemented as proposed, will require carbon reductions on the Navajo Reservation; however, the reduction requirement is less than what is anticipated from unit retirements at the Four Corners and Navajo generating stations associated with Regional Haze requirements (see above).

TEP will continue working with federal and state regulatory authorities, other neighboring utilities, and stakeholders to seek relief from the proposed regulation by reducing the disproportionately high level of carbon emissions reduction for Arizona, and to seek relief from the interim and final proposed compliance requirements. On December 1, 2014, UNS Energy submitted comments on the proposal on behalf of TEP and its other utility subsidiaries. The EPA has received over 3.8 million comments in response to the proposed rule. The proposed rule has been challenged in court and is subject to further legal challenge. TEP cannot predict the ultimate outcome of these matters.

Coal Combustion Residuals Regulations

In December 2014, the EPA signed 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 (RCRA) while allowing for the continued recycling of coal ash. Subject to further review of the rule, we do not anticipate significant impacts to our existing facilities where coal combustion residuals are managed. However, additional requirements will apply to lateral expansions of those existing facilities or to any new facilities.

EMPLOYEES

At December 31, 2014, TEP had 1,448 employees, of which approximately 691 were represented by the International Brotherhood of Electrical Workers (IBEW) Local No. 1116. A new collective bargaining agreement between the IBEW and TEP was entered into in January 2013 and expires in January 2016.

EXECUTIVE OFFICERS OF THE REGISTRANT

Executive Officers, who are elected annually by TEP's Board of Directors, acting at the direction of the Board of Directors of UNS Energy, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
David G. Hutchens	48	President and Chief Executive Officer	2007
Kevin P. Larson	58	Senior Vice President and Chief Financial Officer	1997
Philip J. Dion	46	Senior Vice President, Public Policy and Customer Solutions	2008
Kentton C. Grant	56	Vice President and Treasurer	2007
Todd C. Hixon	48	Vice President and General Counsel	2011
Karen G. Kissinger	60	Vice President and Chief Compliance Officer	1991
Mark C. Mansfield	59	Vice President, Energy Resources	2012
Frank P. Marino	50	Vice President and Controller	2013
Thomas A. McKenna	66	Vice President, Energy Delivery	2007
Catherine E. Ries	55	Vice President, Human Resources and Information Technology	2007
Herlinda H. Kennedy	53	Corporate Secretary	2006

David G. Hutchens	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995.
Kevin P. Larson	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer.
Philip J. Dion	Mr. Dion has served as Senior Vice President, Public Policy and Customer Solutions of TEP since August 2013. Mr. Dion was named Vice President, Public Policy in April 2010. Mr. Dion joined TEP in February 2008 as Vice President of Legal and Environmental Services.
Kentton C. Grant	Mr. Grant was elected Treasurer in 2010 and has served as Vice President of TEP since January 2007. Mr. Grant joined TEP in 1995.
Todd C. Hixon	Mr. Hixon has served as Vice President and General Counsel of TEP since May 2011. Mr. Hixon joined TEP's legal department in 1998 and served in a variety of capacities, most recently serving as Associate General Counsel.
Karen G. Kissinger	Ms. Kissinger has served as Vice President and Chief Compliance Officer of TEP since August 2013. Ms. Kissinger served as Vice President, Controller, and Chief Compliance Officer from 2001 to 2013. Ms. Kissinger joined TEP as Vice President and Controller in January 1991.
Mark C. Mansfield	Mr. Mansfield has served as Vice President, Energy Resources since 2012. He joined the company in 2008, most recently serving as Senior Director of Generation.
Frank P. Marino	Mr. Marino has served as Vice President and Controller of TEP since August 2013. Mr. Marino joined TEP as Assistant Controller in January 2013. Prior to joining TEP, he served various roles at the AES Corporation, a global power company. In 2012 he served as AES' Vice President for Business Demand and Outsourcing Management, and from 2007-2011 he served as Chief Financial Officer for two different business units.
Thomas A. McKenna	Mr. McKenna has served as Vice President, Energy Delivery since August 2013. Mr. McKenna was named Vice President, Engineering in January 2007. Mr. McKenna joined an affiliate of TEP in 1998.
Catherine E. Ries	

	Ms. Ries has served as Vice President, Human Resources and Information Technology, since May 2011. Ms. Ries joined TEP as Vice President of Human Resources in June 2007.
Herlinda H. Kennedy	Ms. Kennedy has served as Corporate Secretary of TEP since September 2006. Ms. Kennedy joined TEP in 1980 and was named assistant Corporate Secretary in 1999.

SEC REPORTS AVAILABLE ON TEP'S WEBSITE

TEP makes available its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practical after we electronically file or furnish them to the Securities and Exchange Commission (SEC). These reports are available free of charge through TEP’s website address at www.tep.com/about/investors/.

UNS Energy’s code of ethics, which applies to the Board of Directors and all officers and employees of UNS Energy and its subsidiaries, including TEP, and any amendments or any waivers made to the code of ethics, is also available on TEP’s website at www.tep.com/about/investors/.

TEP is providing the address of TEP’s website solely for the information of investors and does not intend the address to be an active link. Information contained at TEP’s website is not part of any report filed with the SEC by TEP.

ITEM 1A. RISK FACTORS

The business and financial results of TEP are subject to a number of risks and uncertainties, including those set forth below. These risks and uncertainties fall primarily into five major categories: revenues, regulatory, environmental, financial, and operational.

REVENUES

National and local economic conditions can negatively affect the results of operations, net income, and cash flows at TEP.

Economic conditions have contributed significantly to a reduction in TEP’s retail customer growth and lower energy usage by the company’s residential, commercial, and industrial customers. As a result of weak economic conditions, TEP’s average retail customer base grew by less than 1% in each year from 2010 through 2014 compared with average increases of approximately 2% in each year from 2005 to 2009. TEP estimates that a 1% change in annual retail sales could impact pre-tax net income and pre-tax cash flows by approximately $6 million.

New technological developments and compliance with the ACC's Energy Efficiency Standards will continue to have a significant impact on retail sales, which could negatively impact TEP’s results of operations, net income, and cash flows.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-owned generation, and appliances, equipment, and control systems. Further development and use of these technologies and compliance with the ACC's Energy Efficiency Standard could negatively impact the results of operations, net income, and cash flows of TEP.

The revenues, results of operations, and cash flows of TEP are seasonal, and are subject to weather conditions and customer usage patterns, which are beyond the companies’ control.

TEP typically earns the majority of its operating revenue and net income in the third quarter because retail customers increase their air conditioning usage during the summer. Conversely, TEP’s first quarter net income is typically limited by relatively mild winter weather in its retail service territory. Cool summers or warm winters may reduce customer usage, adversely affecting operating revenues, cash flows, and net income by reducing sales.

TEP is dependent on a small segment of large customers for future revenues. A reduction in the electricity sales to these customers would negatively affect our results of operations, net income, and cash flows.

TEP sells electricity to mines, military installations, and other large industrial customers. In 2014, 35% of TEP’s retail kWh sales were to 608 industrial and mining customers. Retail sales volumes and revenues from these customer classes could decline as a result of, among other things: economic conditions; commodity prices; decisions by the federal government to close military bases; the effects of EE and DG; or the decision by customers to self-generate all or a portion of the energy needs. A reduction in retail kWh sales to TEP’s large customers would negatively affect our results of operations, net income, and cash flows.

REGULATORY

TEP is subject to regulation by the ACC, which sets the company's Retail Rates and oversees many aspects of its business in ways that could negatively affect the company's results of operations, net income, and cash flows.

The ACC is a constitutionally created body composed of five elected commissioners. Commissioners are elected state-wide for staggered four-year terms and are limited to serving a total of two terms. As a result, the composition of the commission, and therefore its policies, are subject to change every two years.

The ACC is charged with setting retail electric rates that provide electric utilities with an opportunity to recover their costs of service and earn a reasonable rate of return. As part of the ACC's process of establishing the retail electric rates charged by TEP, the ACC could disallow the recovery of certain costs, if deemed they were imprudently incurred. The decisions made by the ACC on such matters impact the net income and cash flows of TEP.

Changes in federal energy regulation may negatively affect the results of operations, net income, and cash flows of TEP.

TEP is subject to the impact of comprehensive and changing governmental regulation at the federal level that continues to change the structure of the electric and gas utility industries and the ways in which these industries are regulated. TEP is subject to regulation by the FERC. The FERC has jurisdiction over rates for electric transmission in interstate commerce and rates for wholesale sales of electric power, including terms and prices of transmission services and sales of electricity at wholesale prices.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power systems, including TEP, are subject to mandatory transmission standards developed and enforced by NERC and subject to the oversight of the FERC. Compliance with modified or new transmission standards may subject TEP to higher operating costs and increased capital costs. Failure to comply with the mandatory transmission standards could subject TEP to sanctions, including substantial monetary penalties.

ENVIRONMENTAL

TEP is subject to numerous environmental laws and regulations that may increase its cost of operations or expose it to environmentally-related litigation and liabilities. Many of these regulations could have a significant impact on TEP due to its reliance on coal as its primary fuel for electric generation.

Numerous federal, state, and local environmental laws and regulations affect present and future operations. Those laws and regulations include rules regarding air emissions, water use, wastewater discharges, solid waste, hazardous waste, and management of coal combustion residuals.

These laws and regulations can contribute to higher capital, operating, and other costs, particularly with regard to enforcement efforts focused on existing power plants and new compliance standards related to new and existing power plants. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, authorizations, and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. Failure to comply with applicable laws and regulations may result in litigation, and the imposition of fines, penalties, and a requirement by regulatory authorities for costly equipment upgrades.

Existing environmental laws and regulations may be revised and new environmental laws and regulations may be adopted or become applicable to our facilities. Increased compliance costs or additional operating restrictions from revised or additional regulation could have an adverse effect on our results of operations, particularly if those costs are not fully recoverable from our customers. TEP's obligation to comply with the EPA's BART determinations as a participant in the San Juan, Four Corners, and Navajo plants, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these plants or the ability of individual participants to meet their obligations and continue their participation in these plants. TEP cannot predict the ultimate outcome of these matters.

TEP also is contractually obligated to pay a portion of the environmental reclamation costs incurred at generating stations in which it has a minority interest and is obligated to pay similar costs at the mines that supply these generating stations. While TEP has recorded the portion of its costs that can be determined at this time, the total costs for final reclamation at these sites are unknown and could be substantial.

Proposed federal regulations to limit greenhouse gas emissions would, if adopted in the form proposed, result in a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.
In June 2014 the EPA proposed carbon emission standards to reduce greenhouse gas emissions from existing power plants. EPA's proposal for Arizona would result in a significant shift in generation from coal to natural gas and renewables and could

lead to the early retirement of coal generation in Arizona by 2020. The EPA is scheduled to finalize those standards by summer 2015. These proposed regulations would, if adopted in the form proposed, result in a change in the composition of TEP's generating fleet. As of 01/30/15, approximately 54% of TEP's generating capacity is fueled by coal. In 2014, approximately 68% of our total electricity resources were fueled by coal. The final rule issued by the EPA could significantly impair the ability to operate certain of TEP's coal-fired generation plants on an economically viable basis or at all. A substantial change in TEP's generation portfolio could result in increased cost of operations and/or additional capital investments. The impact of final regulations to address carbon emissions will depend on the specific terms of those measures and cannot be determined at this time.

Early closure of TEP's coal-fired generation plants resulting from environmental regulations could result in TEP recognizing material impairments in respect of such plants and increased cost of operations if recovery of our remaining investments in such plants and the costs associated with such early closures were not permitted through rates charged to customers.

TEP's coal-fired generating stations may be required to be closed before the end of their useful lives in response to recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation plants, or coal handling facilities, from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize a material impairment of its assets and incur added expenses relating to accelerated depreciation and amortization, decommissioning, reclamation and cancellation of long-term coal contracts of such generating plants and facilities. Closure of any of such generating stations may force TEP to incur higher costs for replacement capacity and energy. TEP may not be permitted full recovery of these costs in the rates it charges its customers.

FINANCIAL

The third-party co-owners of Springerville Unit 1 may fail to pay some, or all, of their pro-rata share of the costs and expenses associated with Springerville Unit 1.

TEP owns 49.5% of Springerville Unit 1 and two separate third-parties own the remaining 50.5%. Starting in January 2015, TEP is obligated to operate Springerville Unit 1 for these Third-Party Owners under an existing facility support agreement. TEP and the Third-Party Owners disagree on several key aspects of this agreement, including the allocation of Springerville Unit 1 operating and maintenance expenses, capital improvement costs, and transmission rights. In addition, in late 2014 the Third-Party Owners filed separate complaints at the FERC and in New York State court that include allegations that TEP violated certain provisions of the facility support agreement in relation to TEP's operation of Springerville Unit 1. Because of these disagreements and the pending litigation, the Third-Party Owners may refuse to pay some or all of their pro-rata share of such Springerville Unit 1 costs and expenses. The Third-Party Owners' share of monthly fixed operating and maintenance costs for Springerville Unit 1 is approximately $1.5 million and their share of 2015 capital expenditures is approximately $7 million.

Volatility or disruptions in the financial markets, or unanticipated financing needs, could: increase our financing costs; limit our access to the credit markets; affect our ability to comply with financial covenants in our debt agreements; and increase our pension funding obligations. Such outcomes may adversely affect our liquidity and our ability to carry out our financial strategy.

We rely on access to the bank markets and capital markets as a significant source of liquidity and for capital requirements not satisfied by the cash flow from our operations. Market disruptions such as those experienced in 2008 and 2009 in the United States and abroad may increase our cost of borrowing or adversely affect our ability to access sources of liquidity needed to finance our operations and satisfy our obligations as they become due. These disruptions may include turmoil in the financial services industry, including substantial uncertainty surrounding particular lending institutions and counterparties we do business with, unprecedented volatility in the markets where our outstanding securities trade, and general economic downturns in our utility service territories. If we are unable to access credit at competitive rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our short-term obligations, and execute our financial strategy could be adversely affected.

Changing market conditions could negatively affect the market value of assets held in our pension and other retiree plans and may increase the amount and accelerate the timing of required future funding contributions.

Plant closings or changes in power flows into our service territory could require us to redeem or defease some or all of the tax-exempt bonds issued for our benefit. This could result in increased financing costs.

TEP has financed a substantial portion of utility plant assets with the proceeds of pollution control revenue bonds and industrial development revenue bonds issued by governmental authorities. Interest on these bonds is, subject to certain exceptions,

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excluded from gross income for federal tax purposes. This tax-exempt status is based, in part, on continued use of the assets for pollution control purposes or the local furnishing of energy within TEP’s two-county retail service area.
As of 01/30/15, there were outstanding approximately $324 million aggregate principal amount of tax-exempt bonds that financed pollution control facilities at TEP’s generating units. Should certain of TEP’s generating units be retired and dismantled prior to the stated maturity dates of the related tax-exempt bonds, it is possible that some or all of the bonds financing such facilities would be subject to mandatory early redemption by TEP. As of 01/30/15, there were also outstanding approximately $371 million aggregate principal amount of tax-exempt bonds that financed local furnishing facilities. Depending on changes that may occur to the regional generation mix in the desert southwest, to the regional bulk transmission network, or to the demand for retail energy in TEP’s local service area, it is possible that TEP would no longer qualify as a local furnisher of energy within the meaning of the Internal Revenue Code. If that were to occur, all of TEP’s tax-exempt local furnishing bonds would be subject to mandatory early redemption by TEP or defeasance to the earliest possible redemption date. Of the total tax-exempt local furnishing bonds outstanding, $164 million aggregate principal amount is currently redeemable at par, while the remaining $207 million principal amount can be redeemed at par at the respective bond's early redemption date ranging from 2020 to 2023.
TEP’s net income and cash flows can be adversely affected by rising interest rates.
At December 31, 2014, TEP had $215 million of tax-exempt variable rate debt obligations. The interest rates are set weekly or monthly. The average weekly interest rates (including Letters of Credit (LOCs) and remarketing fees) ranged from 1.40% to 1.75% in 2014. The average monthly interest rates ranged from 0.85% to 0.95%. A 100 basis point increase in the average interest rates on this debt over a twelve-month period would increase TEP’s interest expense by approximately $2 million.
TEP is also subject to risk resulting from changes in the interest rate on its borrowings under the 2010 and 2014 Credit Agreements. Such borrowings may be made on a spread over London Interbank Offer Rate (LIBOR) or an Alternate Base Rate.
If capital market conditions result in rising interest rates, the resulting increase in the cost of variable rate borrowings would negatively impact our results of operations, net income, and cash flows.
The expected purchase of certain of TEP’s leased assets, as well as the cost of significant investments in TEP’s transmission system could require significant outlays of cash, which could be difficult to finance.
In 2014, TEP committed to purchase the Springerville Coal Handling Facilities in April 2015 for a fixed price of $120 million. TEP also leases a 50% undivided interest in Springerville Common Facilities with primary lease terms ending in 2017 and 2021. Upon expiration of the Springerville Coal Handling and Common Facilities Leases, TEP has the obligation under agreements with the owners of Springerville Units 3 and 4 to purchase such facilities. Upon acquisition by TEP, the owner of Springerville Unit 3 has the option and the owner of Springerville Unit 4 has the obligation to purchase from TEP a 14% interest in the Common Facilities and a 17% interest in the Coal Handling Facilities.
OPERATIONAL
The operation of electric generating stations, and transmission and distribution systems, involves risks that could result in reduced generating capability or unplanned outages that could adversely affect TEP’s results of operations, net income, and cash flows.
The operation of electric generating stations, and transmission and distribution systems, involves certain risks, including equipment breakdown or failure, fires and other hazards, interruption of fuel supply, and lower than expected levels of efficiency or operational performance. Unplanned outages, including extensions of planned outages due to equipment failure or other complications, occur from time to time and are an inherent risk of our business. If TEP’s generating stations and transmission and distribution systems operate below expectations, TEP’s operating results could be adversely affected.
The operation of the San Juan Generating Station could be adversely affected if the Participants are unable to secure an economic long-term coal supply.
In connection with the implementation of environmental requirements and the associated retirement of San Juan units 2 and 3, some of the San Juan owner participants (Participants) have expressed a desire to exit their ownership in the plant. As a result, the Participants are attempting to negotiate a restructuring of their San Juan ownership. The current

coal supply contract for San Juan expires on December 31, 2017. The Participants have agreed that prior to executing a binding restructuring agreement, the remaining Participants will need to have greater certainty regarding the cost and availability of fuel for San Juan after December 31, 2017. TEP and other San Juan owners are currently negotiating agreements concerning the future San Juan fuel supply. If the Participants are unable to negotiate an economic fuel supply, the continued operation of San Juan could be jeopardized resulting in the retirement of San Juan Unit 1 earlier than expected. At December 31, 2014, the net book value of TEP's investment in San Juan Unit 1 is $96 million.

TEP receives power from certain generating facilities that are jointly owned and operated by third parties. Therefore, TEP may not have the ability to affect the management or operations at such facilities which could adversely affect TEP’s results of operations, net income, and cash flows.

Certain of the generating stations from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have the sole discretion or any ability to affect the management or operations at such facilities. As a result of this reliance on other operators, TEP may not be able to ensure the proper management of the operations and maintenance of the plants. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing regulations which may affect such facilities. In addition, TEP will not have sole discretion as to how to proceed in the face of requirements relating to environmental compliance which could require significant capital expenditures or the closure of such generating stations. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such generating facilities could negatively impact the business and operations of TEP.

We may be subject to physical attacks.

As operators of critical energy infrastructure, we may face a heightened risk of physical attacks on our electric systems. Our electric generation, transmission, and distribution assets and systems are geographically dispersed and are often in rural or unpopulated areas which make them especially difficult to adequately detect, defend from, and respond to such attacks.

If, despite our security measures, a significant physical attack occurred, we could have our operations disrupted, property damaged, experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

We may be subject to cyber attacks.

We may face a heightened risk of cyber attacks. Our information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, and other causes. Our operations technology systems have direct control over certain aspects of the electric system and, in addition, our utility business requires access to sensitive customer data, including personal and credit information, in the ordinary course of business.

If, despite our security measures, a significant cyber breach occurred, we could have our operations disrupted, property damaged, and customer information stolen; experience loss of revenues, response costs, and other financial loss; and be subject to increased regulation, litigation, and damage to our reputation, any of which could have a negative impact on our business and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Transmission facilities owned by TEP and by third parties are located in Arizona and New Mexico and transmit the output from TEP’s electric generating stations at Four Corners, Navajo, San Juan, Springerville, Gila River, and Luna to the Tucson area for use by TEP’s retail customers. The transmission system is interconnected at various points in Arizona and New Mexico with other regional utilities. TEP has arrangements with approximately 140 companies to interchange generation capacity and for the transmission of energy. See Item 1. Business, TEP, Generating and Other Resources.

At December 31, 2014, TEP owned or participated in an overhead electric transmission and distribution system consisting of:

- 564 circuit-miles of 500-kV lines;
- 1,110 circuit-miles of 345-kV lines;
- 408 circuit-miles of 138-kV lines;

- 465 circuit-miles of 46-kV lines; and
- 2,600 circuit-miles of lower voltage primary lines.

TEP's underground electric distribution system includes 4,461 cable-miles of lines. TEP owns approximately 77% of the poles on which its lower voltage lines are located. Electric substation capacity consists of 106 substations with a total installed transformer capacity of 15,809,050 kilovolt amperes.

The electric generating stations (except as noted below), administrative headquarters, warehouses and service centers are located on land owned by TEP. The electric distribution and transmission facilities owned by TEP are located:

- on property owned by TEP;
- under or over streets, alleys, highways, and other places in the public domain, as well as in national forests and state lands, under franchises, easements, or other rights which are generally subject to termination;
- under or over private property as a result of easements obtained primarily from the record holder of title; or
- over American Indian reservations under grant of easement by the Secretary of Interior or lease by American Indian tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or liens existing at the time the easements were acquired.

Springerville is located on property held by TEP under a long-term surface ownership agreement with the State of Arizona.

Four Corners and Navajo are located on properties held under easements from the United States and under leases from the Navajo Nation. TEP, individually and in conjunction with PNM in connection with San Juan, has acquired land rights, easements and leases for the plant, transmission lines and a water diversion facility located on land owned by the Navajo Nation. TEP also has acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo across the Zuni, Navajo, and Tohono O'odham American Indian Reservations. TEP, in conjunction with PNM and Samchully Power & Utilities 1 LLC, holds an undivided ownership interest in the property on which Luna is located.

TEP's rights under these various easements and leases may be subject to defects such as:

- possible conflicting grants or encumbrances due to the absence of, or inadequacies in, the recording laws or record systems of the Bureau of Indian Affairs (BIA) and the American Indian tribes;
- possible inability of TEP to legally enforce its rights against adverse claimants and the American Indian tribes without Congressional consent; or
- failure or inability of the American Indian tribes to protect TEP's interests in the easements and leases from disruption by the U.S. Congress, Secretary of the Interior, or other adverse claimants.

These possible defects have not interfered, and are not expected to materially interfere, with TEP's interest in and operation of its facilities.

TEP, under separate sale and leaseback arrangements, leased the following generation facilities (which do not include land):

- Springerville Unit 1 which expired in January 2015;
- Springerville Coal Handling Facilities; and
- a 50.0% undivided interest in the Springerville Common Facilities.

Under separate ground lease agreements, TEP leased parcels of land for the following photovoltaic facilities:

- The Solar Zone in two areas, Area J and Area B, of the University of Arizona Tech Park in Pima County, Arizona; and
- Bright Tucson Community Solar Blocks in Pima County, Arizona.

In December 2014, TEP placed in service an additional photovoltaic facility in Cochise County, Arizona, for which TEP entered into a 30-year easement agreement. The easement is to facilitate the operations of a solar photovoltaic renewable energy generation system on behalf of the Department of the Army, located at Fort Huachuca in Cochise County.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Springerville Unit 1 and Note 5 of Notes to Consolidated Financial Statements.

ITEM 3. LEGAL PROCEEDINGS

Springerville Unit 1 Proceedings

Upon the termination of the Springerville Unit 1 Leases on January 1, 2015, 50.5% of Springerville Unit 1, or 195 MW of capacity, continued to be owned by third parties, i.e. 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' Springerville Unit 1 power.

Commencing on January 1, 2015 with the termination of the leases, TEP is obligated to operate the unit for the Third-Party Owners under an existing facility support agreement. In 2014, TEP and the Third-Party Owners engaged in discussions regarding the post-lease operation of Springerville Unit 1 and related cost sharing arrangements, but did not reach agreement on several key points.

On November 7, 2014, the Third-Party Owners filed a complaint (FERC Action) against TEP at the FERC alleging that TEP had not agreed to wheel power and energy for the Third-Party Owners in the manner specified in the facility support agreement 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 after the leases terminate to the locations and for the price specified by the Third-Party Owners. On December 3, 2014, TEP filed an answer to the FERC Action denying the allegations and requesting that the FERC dismiss the complaint. On February 19, 2015, the FERC issued an order denying the Third-Party Owners complaint.

On December 19, 2014, the Third-Party Owners filed a complaint (New York Action) against TEP in the Supreme Court of the State of New York, New York County, alleging, among other things, that TEP has refused to comply with the Third-Party Owners instructions to schedule power and energy to which they are entitled in respect of their undivided interest after the leases terminate on January 1, 2015, that TEP failed to comply with their instructions to specify the level of fuel and fuel handling services effective January 1, 2015, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases, that TEP has not agreed to wheel power and energy in the manner required by the facility support agreement as set forth in the FERC Action and that TEP has breached fiduciary duties claimed to be owed to the Third-Party Owners. The New York Action seeks declaratory judgments, injunctive relief, damages in an amount to be determined at trial and the Third-Party Owners' fees and expenses.

On December 22, 2014, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent a notice to TEP referencing the New York Action, stating that the New York Action alleges that TEP has disaffirmed or repudiated certain of its obligations under the lease transaction documents and that such disaffirmances and repudiations constitute events of default under the Third-Party Owners' leases. The notice states that the owner trustees, as lessors, are exercising their rights to keep the undivided interests idle and demanding that TEP pay, on January 1, 2015, liquidated damages totaling approximately $71 million. The notice also states that any rights to exercise additional remedies or assert additional events of default are preserved. In a letter to Wilmington Trust Company dated December 29, 2014, TEP denied the allegations in the notice. In January 2015, Wilmington Trust Company sent a second notice to TEP that alleges that TEP has defaulted under the Third-Party Owners' leases by not remediating the defaults alleged in the first notice. The second notice repeated the demand that TEP pay liquidated damages totaling approximately $71 million. In a letter to Wilmington Trust Company, TEP denied the allegations in the second notice.

TEP believes that it has fully complied with all of its obligations under the two Third-Party Owner leases and the other lease transaction agreements, denies that it has disaffirmed or repudiated any of its obligations under the lease transaction documents, denies that any of the amounts claimed as damages are due, denies the allegation that events of default have arisen under such leases and denies that the lessors are entitled to exercise remedies under such leases. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations, Springerville Unit 1. In addition, see Note 6 of Notes to Consolidated Financial Statements - Contingencies.

ITEM 4. MINE SAFETY DISCLOSURES
Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Stock Trading

TEP's common stock is wholly-owned by UNS Energy and is not listed for trading on any stock exchange.

Dividends

TEP paid dividends to UNS Energy of $40 million in 2014, $40 million in 2013, and $30 million in 2012.

TEP can pay dividends if it maintains compliance with the 2014 Credit Agreement, the 2010 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement which all contain substantially the same financial covenants, and the terms of the Merger order issued by the ACC in August 2014. At December 31, 2014, TEP was in compliance with the terms of all financial covenants and agreements and the Merger order.

ITEM 6. SELECTED FINANCIAL DATA

	2014	2013	2012	2011	2010
	Thousands of Dollars				
Income Statement Data					
Operating Revenues	$1,269,901	$1,196,690	$1,161,660	$1,156,386	$1,125,267
Net Income	102,338	101,342	65,470	85,334	108,260
Balance Sheet Data					
Total Utility Plant – Net	$3,425,190	$2,944,455	$2,750,421	$2,650,652	$2,410,077
Total Investments in Lease Debt and Equity	—	36,194	45,457	65,829	103,844
Other Investments and Other Property	37,599	33,488	35,091	32,313	43,588
Total Assets	4,232,422	3,563,285	3,461,046	3,277,661	3,078,411
Long-Term Debt	$1,372,414	$1,223,070	$1,223,442	$1,080,373	$1,003,615
Non-Current Capital Lease Obligations	69,438	131,370	262,138	352,720	429,074
Common Stock Equity	1,215,779	925,923	860,927	824,943	709,884
Total Capitalization	$2,657,631	$2,280,363	$2,346,507	$2,258,036	$2,142,573
Cash Flow Data					
Net Cash Flows From Operating Activities	$313,663	$346,191	$267,919	$268,294	$302,483
Capital Expenditures	(507,070)	(252,848)	(252,782)	(351,890)	(277,309)
Other Investing Cash Flows	(10,568)	(6,814)	24,901	39,879	24,273
Net Cash Flows From Investing Activities	(517,638)	(259,662)	(227,881)	(312,011)	(253,036)
Net Cash Flows From Financing Activities	252,810	(140,937)	11,987	51,452	(51,882)
Ratio of Earnings to Fixed Charges [1]	2.56	2.67	2.10	2.40	2.74

(1) 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, interest on operating lease payments, and expense on indebtedness, including capital lease obligations.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

- outlook and strategies;
- operating results during 2014 compared with the same periods of 2013, and 2013 compared with 2012;
- factors affecting our results and outlook;
- liquidity, capital needs, capital resources, and contractual obligations;
- dividends; and
- critical accounting estimates.

TEP is a vertically integrated, regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric customers in a 1,155 square mile area in southeastern Arizona.

Management's Discussion and Analysis includes financial information prepared in accordance with generally accepted accounting principles (GAAP) in the U.S., 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 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 Item 6 of this Form 10-K and the Consolidated Financial Statements and Notes in Item 8 of this Form 10-K. 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 Item 1A.

OUTLOOK AND STRATEGIES

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

- Continuing to focus on our long-term generation resource strategy including shifting from coal to natural gas, renewables, and energy efficiency while providing rate stability for our customers, mitigating environmental impacts, complying with regulatory requirements, and leveraging our existing utility infrastructure.
- Developing strategic responses to new environmental regulations and potential new legislation, including proposed carbon emission standards to reduce greenhouse gas emissions from existing power plants. We are evaluating TEP's existing mix of generation resources and defining steps to achieve environmental objectives that protect the financial stability of our utility business 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.
- Focusing on our core utility business through operational excellence, investing in utility rate base, emphasizing customer service, and maintaining a strong community presence.
- Developing strategic responses to the evolving utility business that includes renewable energy, DG, and EE that protect the financial stability of our business while providing benefits and choices to our customers.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations for the years ended December 31, 2014, 2013 and 2012.

2014 compared with 2013

TEP reported net income of $102 million in the year ended December 31, 2014 compared with net income of $101 million in the year ended December 31, 2013. The following factors affected the period over period change in TEP’s results. All amounts are presented on an after-tax basis:

- a $22 million increase in retail margin revenues due to a non-fuel base rate increase that was effective on July 1, 2013 and a $6 million increase in LFCR revenues recorded in 2014;
- a $7 million decrease in interest expense, primarily due to a reduction in the balance of capital lease obligations. See Note 5 of the Notes to Consolidated Financial Statements;
- a $2 million increase in the margin on long-term wholesale sales, due in part to an increase in the average market price for wholesale power; and
- a $1 million increase in transmission revenue; partially offset by
- an $11 million increase in Base O&M for retail customer bill credits approved by the ACC as a condition of the Merger;
- a $7 million increase in Base O&M for merger-related expenses including acquisition transaction fees and the acceleration of share-based compensation expense;
- a $4 million increase in Base O&M exclusive of bill credits and merger-related expenses. The increase results primarily from higher generating plant maintenance expense and increased rent expense associated with the Navajo lease amendment. See Note 6 of Notes to Consolidated Financial Statements;
- a $4 million increase in depreciation and amortization expenses, resulting primarily from an increase in asset base in the current year; and
- a $5 million increase in income taxes resulting from an effective tax rate variance primarily generated by a non-recurring $11 million tax benefit recorded in June 2013 to recover previously recorded income tax expense as a result of the 2013 TEP Rate Order. This amount is partially offset by a $2 million increase in the valuation allowance in 2013 and a $3 million increase in investment tax credits recorded in 2014. See Note 11 of Notes to Consolidated Financial Statements.

2013 compared with 2012

TEP reported net income of $101 million in 2013 compared with net income of $65 million in 2012. The following factors affected the period over period change in TEP’s results. All amounts are presented on an after-tax basis:

- a $25 million increase in retail margin revenues primarily due to a non-fuel base rate increase that was effective on July 1, 2013, and favorable weather during 2013 compared with 2012. Favorable weather conditions contributed to a 0.2% increase in retail kWh sales during 2013;
- a $9 million decrease in income taxes, resulting from an effective tax rate variance primarily generated by a non-recurring $11 million tax benefit related to a regulatory asset recorded in June 2013 to recover previously recorded income tax expense through future rates as a result of the 2013 TEP Rate Order. See Note 11 of Notes to Consolidated Financial Statements;
- a $5 million decrease in interest expense due to a reduction in the balance of capital lease obligations;
- a $3 million increase in income as a result of the 2012 write-off of a portion of the planned Tucson to Nogales transmission line;
- a $2 million increase in income related to the operation of Springerville Units 3 and 4. An unplanned outage at Springerville Unit 3 negatively affected results in 2012; and
- a $1 million increase in the margin on long-term wholesale sales due in part to an increase in the market price for wholesale power; partially offset by

- a $4 million increase in Base O&M for merger-related expenses recorded in December 2013;
- a $4 million increase in Base O&M, exclusive of merger-related costs, due in part to higher planned and unplanned generating plant maintenance expense;
- a charge of $2 million recorded to fuel and purchased energy expense resulting from the 2013 TEP Rate Order; and
- a $2 million increase in taxes other than income taxes due in part to an increase in property tax rates and higher asset balances.

Utility Sales and Revenues

The table below provides a summary of retail kWh sales, revenues, and weather data during 2014, 2013 and 2012:

	Year Ended		Increase (Decrease)		Year Ended	Increase (Decrease)	
	2014	2013	Percent[1]		2012	Percent[1]	
Energy Sales, kWh (in Millions):							
Electric Retail Sales:							
Residential	3,727	3,867	(3.6	)%	3,821	1.2	%
Commercial	2,170	2,187	(0.8	)%	2,187	—	%
Industrial	2,098	2,114	(0.8	)%	2,132	(0.9	)%
Mining	1,137	1,079	5.4	%	1,093	(1.2	)%
Public Authorities	33	32	3.1	%	32	1.6	%
Total Electric Retail Sales	9,165	9,279	(1.2	)%	9,265	0.2	%
Retail Margin Revenues (in Millions):							
Residential	$280	$271	3.3	%	$248	9.3	%
Commercial	188	181	3.9	%	171	5.9	%
Industrial	104	97	7.2	%	93	5.4	%
Mining	38	34	11.8	%	30	11.5	%
Public Authorities	2	2	—	%	2	5.9	%
Total by Customer Class	612	585	4.6	%	544	7.7	%
LFCR Revenues	11	2	450.0	%	—	NM	
Total Retail Margin Revenues (Non-GAAP)[2]	623	587	6.1	%	544	7.9	%
Fuel and Purchased Power Revenues	303	300	1.0	%	327	(8.1	)%
RES, DSM and ECA Revenues	44	47	(6.4	)%	45	4.4	%
Total Retail Revenues (GAAP)	$970	$934	3.9	%	$916	2.0	%
Average Retail Margin Rate (Cents / kWh):[1]							
Residential	7.51	7.02	7.0	%	6.50	8.0	%
Commercial	8.66	8.28	4.6	%	7.82	5.9	%
Industrial	4.96	4.61	7.6	%	4.33	6.5	%
Mining	3.34	3.14	6.4	%	2.78	12.9	%
Public Authorities	6.06	5.56	9.0	%	5.34	4.1	%
Total Average Retail Margin Rate Excluding LFCR	6.68	6.30	6.0	%	5.87	7.3	%
Average LFCR Rate	0.12	0.02	500.0	%	—	NM	
Total Average Retail Margin Rate Including LFCR	6.80	6.31	7.8	%	5.87	7.5	%
Average Fuel and Purchased Power Revenues	3.31	3.24	2.2	%	3.52	(8.0	)%
Average RES, DSM and ECA Revenues	0.48	0.52	(7.7	)%	0.49	6.1	%
Total Average Retail Revenues	10.59	10.07	5.2	%	9.88	1.9	%
Weather Data:							
Cooling Degree Days							
Year Ended December 31,	1,557	1,631	(4.5	)%	1,556	4.8	%
10-Year Average	1,515	1,491	NM		1,484	NM	
Heating Degree Days							
Year Ended December 31,	930	1,449	(35.8	)%	1,201	20.6	%
10-Year Average	1,335	1,404	NM		1,394	NM	

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

(2) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to Total Retail Revenues, which is determined in accordance with GAAP. Retail Margin Revenues exclude: (i) revenues collected from retail customers that are directly offset by expenses recorded in other line items; and (ii) revenues collected

from third parties that are unrelated to kWh sales to retail customers. We believe the change in Retail Margin Revenues between periods provides useful information because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales and LFCR revenues available to cover the non-fuel operating expenses of our core utility business.

2014 compared with 2013

Residential

Residential kWh sales were 3.6% lower in 2014 due in part to fewer cooling degree days compared with 2013. A non-fuel base rate increase effective July 1, 2013, partially offset by lower sales volumes, led to an increase in residential margin revenues of 3.3%, or $9 million. The average number of residential customers grew by 0.5% in 2014 compared with 2013.

Commercial

Commercial kWh sales decreased by 0.8% compared with 2013. Lower sales volumes were offset by a non-fuel base rate increase effective July 1, 2013 which contributed to an increase in commercial margin revenues of 3.9%, or $7 million.

Industrial

Industrial kWh sales decreased by 0.8% compared with 2013. Lower sales volumes were offset by a non-fuel base rate increase effective July 1, 2013, which led to an increase in industrial margin revenues of 7.2% or $7 million.

Mining

Mining kWh sales increased by 5.4% compared with 2013, which can be attributed to an expansion by one of TEP's mining customers. The increased kWh sales as well as a non-fuel base rate increase effective July 1, 2013 led to an increase in margin revenues from mining customers of 11.8%, or $4 million. See Factors Affecting Results of Operations, Sales to Mining Customers.

2013 compared with 2012

Residential

Residential kWh sales were 1.2% higher in 2013 due in part to favorable weather conditions compared with 2012. A non-fuel base rate increase effective July 1, 2013 and higher sales volumes led to an increase in residential margin revenues of 9.3%, or $23 million. The average number of residential customers grew by 0.7% in 2013 compared with 2012.

Commercial

Commercial kWh sales were the same when compared with 2012. A non-fuel base rate increase effective July 1, 2013 contributed to an increase in commercial margin revenues of 5.9%, or $10 million.

Industrial

Industrial kWh sales decreased by 0.9% compared with 2012. Lower sales due to certain customers changing their usage patterns were more than offset by a non-fuel base rate increase effective July 1, 2013, which led to an increase in industrial margin revenues of $4 million.

Mining

Mining kWh sales decreased by 1.2% compared with 2012. One of TEP's mining customers performed maintenance on its facilities resulting in a temporary decrease in production. A non-fuel base rate increase effective July 1, 2013 led to an increase in margin revenues from mining customers of 11.5%, or $4 million.

Wholesale Sales and Transmission Revenues

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Long-Term Wholesale Revenues:			
Long-Term Wholesale Margin Revenues (Non-GAAP)[1]	$10	$7	$5
Fuel and Purchased Power Expense Allocated to Long- Term Wholesale Revenues	18	19	20
Total Long-Term Wholesale Revenues	28	26	25
Transmission Revenues	16	15	16
Short-Term Wholesale Revenues	114	92	70
Electric Wholesale Sales (GAAP)	$158	$133	$111

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

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

Short-Term Wholesale Revenues

All revenues from short-term wholesale sales and 10% of the profits from wholesale trading activity are credited against the fuel and purchased power costs eligible for recovery in the PPFAC.

Other Revenues

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Revenue related to Springerville Units 3 and 4[1]	$112	$102	$101
Other Revenue	29	28	33
Total Other Revenue	$141	$130	$134

(1) Represents revenues and reimbursements from Tri-State, the lessee of Springerville Unit 3, and 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., an indirect wholly-owned subsidiary of UNS Energy (UNS Gas) and UNS Electric, for corporate services provided by TEP, and miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees. See Note 4 of Notes to Consolidated Financial Statements.

Operating Expenses

Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources for 2014, 2013, and 2012 are detailed below:

	Generation and Purchased Power			Fuel and Purchased Power Expense		
	2014	2013	2012	2014	2013	2012
	Millions of kWh			Millions of Dollars		
Coal-Fired Generation	9,271	10,254	9,702	$232	$273	$247
Gas-Fired Generation	1,210	1,007	1,435	60	46	65
Utility Owned Renewable Generation	48	38	45	—	—	—
Reimbursed Fuel Expense for Springerville Units 3 and 4	—	—	—	5	7	7
Total Generation	10,529	11,299	11,182	298	326	319
Total Purchased Power	3,195	2,329	2,328	153	112	80
Transmission and Other PPFAC Recoverable Costs	—	—	—	18	12	6
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	—	(11)	(12)	31
Subtotal	13,724	13,628	13,510	$457	$438	$436
Less Line Losses and Company Use	(859)	(885)	(839)			
Total Energy Sold	12,865	12,743	12,671			

Generation

Total generating output decreased in 2014 when compared with 2013 primarily resulting from outages at Springerville and Sundt generating stations. Coal-fired generation decreased by 9.5% in 2014, primarily due to using natural gas to fuel Sundt Unit 4 instead of coal.

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

	2014	2013	2012
	cents per kWh		
Coal	2.50	2.66	2.54
Gas	4.99	4.57	4.54
Purchased Power	4.79	4.83	3.44
All Sources	3.64	3.54	3.19

O&M

The table below summarizes the items included in O&M expense. Base O&M includes $34 million of merger-related expenses and retail customer bill credits in 2014 and $6 million of merger-related expenses in 2013.

	2014	2013	2012
	Millions of Dollars		
Base O&M (Non-GAAP)[1]	$281	$246	$234
O&M Recorded in Other Expense	(9)	(7)	(6)
Reimbursed Expenses Related to Springerville Units 3 and 4	84	70	72
Expenses Related to Customer Funded Renewable Energy and DSM Programs[2]	23	26	35
Total O&M (GAAP)	$379	$335	$335

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

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

	2014	2013	2012
	Millions of Dollars		
Pension Expense Charged to O&M	$6	$10	$10
Retiree Benefit Expense Charged to O&M	5	5	5
Total	$11	$15	$15

FACTORS AFFECTING RESULTS OF OPERATIONS

2013 TEP Rate Order

The 2013 TEP Rate Order, issued by the ACC and effective July 1, 2013, provided for a non-fuel retail Base Rate increase of $76 million, an authorized rate of return of 7.26% on the Original Cost Rate Base (OCRB) of $1.5 billion, and a 0.68% return on the fair value increment of rate base (the fair value increment of rate base represents the difference between OCRB and Fair Value Rate Base (FVRB) of approximately $800 million).

In addition, there are provisions within the 2013 TEP Rate Order allowing more timely recovery of certain costs through several recovery mechanisms:

- The LFCR mechanism allows recovery of certain non-fuel costs related to kWh sales lost due to EE programs and DG.
- The Environmental Compliance Adjustor (ECA) mechanism allows recovery of certain capital carrying costs to comply with government-mandated environmental regulations between rate cases.
- The DSM and RES surcharges allow for recovery of costs to implement DSM and renewable energy programs that support the ACC's EE Standards.

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

See Note 2 of Notes to Consolidated Financial Statements for more information.

Generating Resources

At December 31, 2014, approximately 57% of TEP's generating capacity was fueled by coal. In January 2015, following the purchase of the final Springerville Unit 1 leased interest of 96 MW, and the expiration of the remaining 195 MW of Springerville Unit 1 leased capacity, TEP's coal-fired generating capacity dropped to 54% of total capacity. Existing and proposed federal environmental regulations, as well as potential changes in state regulation, may increase the cost of operating coal-fired generating facilities. TEP is implementing coal reduction strategies and evaluating additional steps for reducing the proportion of coal in its fuel mix. TEP's ability to reduce its coal-fired generating capacity will depend on several factors, including, but not limited to:

- Regulatory approvals associated with the closure of San Juan Unit 2, and pending ownership restructuring of the remaining units, see Item 1 - Environmental Matters;
- The outcome of the proposed Clean Power Plan, see Item 1 - Environmental Matters; and
- TEP's option to permanently convert Sundt Unit 4 to be fueled by natural gas, see Item 1 - Environmental Matters.

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 resulting in TEP owning a 49.5% undivided interest. At December 31, 2014, TEP's ownership interest was 24.7%, or 96 MW.

In 2006, TEP purchased a 14.1% undivided ownership interest in Springerville Unit 1, representing approximately 55 MW of capacity. In December 2014, TEP purchased a 10.6% leased interest in Springerville Unit 1, representing 41 MW of capacity, for $20 million. In January 2015, TEP purchased a leased interest comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million.

The remaining 50.5% of Springerville Unit 1, or 195 MW of capacity, continues to be owned by third parties. TEP is not obligated to purchase any of the Third-Party Owners' generating output. With the expiration of the leases in January 2015, 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 $1.5 million per month, and their share of capital expenditures, which are approximately $7 million in 2015.

In 2014, TEP and the Third-Party Owners, engaged in discussions regarding the post-lease operation of Springerville Unit 1 and related cost sharing arrangements, but did not reach agreement on several key points. As of 01/30/15, TEP has requested pre-funding for operations from the Third-Party Owners of approximately $5 million for their pro-rata share of Springerville Unit 1 operating and maintenance expenses and for their pro-rata share of capital costs, none of which has been paid as of February 19, 2015.

See Item 3. Legal Proceedings for a description of legal proceedings relating to the Third-Party Owners.

TEP replaced the 195 MW of expired leased capacity with the purchase of Gila River Unit 3. See Gila River Generating Station Unit 3, below.

Gila River Generating Station Unit 3

On December 10, 2014, TEP and UNS Electric acquired Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW located in Gila Bend, Arizona, from a subsidiary of Entegra Power Group LLC. TEP purchased a 75% undivided interest in Gila River Unit 3 (413 MW) for $164 million, and UNS Electric purchased the remaining 25% undivided interest. TEP's interest in Gila River Unit 3 will replace the expired coal-fired leased capacity from Springerville Unit 1 and the expected reduction of coal-fired generating capacity from San Juan Unit 2 and is a key component in TEP's strategy to diversify its generation fuel mix.

See Note 7 of Notes to Consolidated Financial Statements and Item 7. Management's Discussion and Analysis of Financial Condition and Factors Affecting Results of Operations, Gila River Generating Station Unit 3.

Potential Plant Retirements

TEP periodically files an Integrated Resource Plan (IRP) with the ACC. The IRP provides a view of forecasted energy needs over a long term (15 years) and options being considered to meet those needs. TEP's 2014 IRP reflects a portfolio diversification strategy that includes reducing its overall coal capacity over the next five years at the Springerville, San Juan, and Sundt Generating Stations. TEP's planning assumptions include retiring certain coal-fired generating facilities at San Juan and coal handling facilities at Sundt earlier than their current estimated useful lives. These facilities currently do not have the requisite emission control equipment to meet proposed EPA regulations. TEP continues to evaluate the potential need to retire early these coal-fired generating facilities. The 2013 TEP Rate Order stipulates that in any filing related to the early retirement of a generation asset, TEP would seek ACC approval to apply any then-existing excess generation depreciation reserve to the unrecovered book value of the retiring assets. TEP would then seek regulatory recovery for any remaining amounts that would not be otherwise recovered, if and when any such assets are retired.

See Item 1 - Business, Environmental Matters.

Springerville Coal Handling Facilities Capital Lease Purchase Commitment

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

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

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Upon TEP’s purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities.

Sales to Mining Customers

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

In addition to the mining customers that TEP currently serves, the proposed Rosemont Copper Mine near Tucson, Arizona is in the final stages of permitting. If the Rosemont Copper Mine is constructed and reaches full production, it would be expected to become TEP's largest retail customer, with TEP serving the mine's estimated load of approximately 85 MW.

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

Springerville Units 3 and 4

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

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

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Other Revenues	$112	$102	$101
Fuel Expense	(5)	(7)	(7)
O&M Expense	(84)	(69)	(72)
Taxes Other Than Income Taxes	(1)	(2)	(1)

Interest Rates

See Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Fair Value Measurements

See Note 10 of Notes to Consolidated Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

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

	As of December 31, 2014
	Millions of Dollars
Cash and Cash Equivalents	$74
Borrowings under Revolving Credit Facilities[1]	85
Amount Available under Revolving Credit Facilities	185

[1] Includes an LOC issued under the 2010 Credit Agreement.

Short-term Investments

TEP’s short-term investment policy governs the investment of excess cash balances. We regularly review and update this policy in response to market conditions. At December 31, 2014, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facilities

We have access to working capital through revolving credit agreements with lenders. Each of these agreements is a committed facility with various expiration dates. The 2014 revolving credit facility may be used for revolving borrowings. The 2010 revolving credit facility may be used for revolving borrowings as well as to issue trade LOCs. TEP issues LOCs from time to time to provide credit enhancement to counterparties for its energy procurement and hedging activities.

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. However, TEP will need to issue additional long-term debt by April 2015 in order to complete the purchase of the Springerville Coal Handling Facilities and to ensure adequate revolving credit capacity through the second and third quarters of 2015. Further, TEP will need to issue additional debt by November 2015 to repay amounts borrowed under the 2014 Credit Agreement. See Item 7A Quantitative and Qualitative Disclosures about Market Risk.

Cash Flows

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

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Net Cash Flows – Operating Activities (GAAP)	$314	$346	$268
Net Cash Flows – Investing Activities (GAAP)	(518)	(260)	(228)
Net Cash Flows – Financing Activities (GAAP)	253	(141)	12
Net Increase (Decrease) in Cash	49	(55)	52
Beginning Cash	25	80	28
Ending Cash	$74	$25	$80

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

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Net Cash Flows – Operating Activities (GAAP)	$314	$346	$268
Less: Capital Expenditures(1)	(507)	(253)	(253)
Net Cash Flows after Capital Expenditures (Non-GAAP)(2)	(193)	93	15
Less: Payments of Capital Lease Obligations	(165)	(100)	(89)
Plus: Proceeds from Investment in Lease Debt	—	9	19
Net Cash Flows after Capital Expenditures and Required Payments on Debt and Capital Lease Obligations (Non-GAAP)(2)	$(358)	$2	$(55)

(1) Includes the purchase of Gila River Unit 3 ($164 million) and Springerville Unit 1 Leased Assets ($20 million) separately presented on the Cash Flow Statement.

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

TEP had unusually large expenditures in 2014 related to the purchase of both Gila River Unit 3 and Springerville Unit 1 leased assets. Additionally, the structure of our Springerville Unit 1 Leases, that expired on January 1, 2015, required disproportionately large lease payments in 2014. Our capital requirements were met with a combination of equity contributions from UNS Energy and long-term borrowings as discussed in Financing Activities below. As shown in our forecasted capital expenditures table below, TEP expects capital requirements to remain high in 2015 and then taper off in 2016 through 2019. We expect to issue new long-term debt in 2015 to meet our capital requirements.

Operating Activities

2014 Compared with 2013

In 2014, net cash flows from operating activities were $32 million lower compared with 2013. The decrease was due primarily to: $15 million of merger-related costs; $12 million of increased incentive compensation payments; and an increase of $6 million of capital lease interest paid.

2013 Compared with 2012

In 2013, net cash flows from operating activities were $78 million higher than in 2012. The increase was due primarily to: a $34 million increase in cash receipts from retail and wholesale sales, net of fuel and purchased power costs paid, resulting from a base rate increase that became effective on July 1, 2013, an increase in retail sales volumes, and an increase in wholesale power prices; a $30 million decrease in operations and maintenance costs paid due in part to lower renewable prepayments, lower incentive payments under DSM programs, and lower payments for remote generating stations; and a $6 million decrease in capital lease interest paid due to a decline in capital lease obligation balances; partially offset by a $6 million increase in wages paid (net of amounts capitalized).

Investing Activities

2014 Compared with 2013

Net cash flows used for investing activities increased by $258 million in 2014 compared with 2013 due primarily to: the purchase of a 75% interest in Gila River Unit 3 for $164 million; the purchase of a 10.6% interest in Springerville Unit 1 for $20 million; and a $71 million increase in capital expenditures to fund the construction of new solar projects and improvements to our generating facilities. TEP's capital expenditures, including the purchase of Gila River Unit 3 and the Springerville Unit 1 lease interest, were $507 million in 2014 and $253 million in 2013.

2013 Compared with 2012

Net cash flows used for investing activities increased by $32 million in 2013 compared with 2012 due primarily to: a $14 million increase in purchases of RECs due to an increase in renewable energy PPAs; and $10 million in lower proceeds from investment in lease debt. TEP’s capital expenditures were $253 million in each of 2013 and 2012.

TEP's forecasted capital expenditures are summarized below:

	2015	2016	2017	2018	2019
	Millions of Dollars				
Transmission and Distribution	$211	$102	$86	$89	$100
Generation Facilities	96	74	100	72	44
Renewable Energy Generation	27	35	29	29	29
Springerville Lease Purchases[1]	119	—	38	—	—
General and Other	55	41	41	41	52
Total Capital Expenditures	$508	$252	$294	$231	$225

(1) Includes: Springerville Unit 1 lease interest purchase of $46 million in 2015; TEP's portion of the Springerville Coal Handling facilities purchase of $73 million (net of expected reimbursements from Tri-State and SRP) in 2015; and Springerville Common facilities purchase of $38 million in 2017.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

Financing Activities

2014 Compared with 2013

In 2014, net cash from financing activities was $394 million higher than the same period last year due to: proceeds from the issuance of $149 million of long-term debt; an $85 million increase in borrowings (net of repayments) under TEP's revolving credit facilities; and $225 million of UNS Energy equity contributions; partially offset by a $66 million increase in payments of capital lease obligations.

Following completion of the Merger, Fortis made equity investments in UNS Energy totaling $287 million. UNS Energy then contributed a total of $225 million to TEP. These equity investments in TEP helped fund the Gila River Unit 3 and Springerville Unit 1 purchase commitments.

2013 Compared with 2012

In 2013, net cash from financing activities was $153 million lower than 2012. Financing activities in 2013 included a $10 million increase in dividend payments to UNS Energy and a $10 million increase in payments made on capital lease obligations. Financing activities in 2012 included: the issuance of $150 million of long-term debt; $7 million of repayments of long-term debt; and $10 million of repayments (net of borrowings) under the TEP Revolving Credit Facility.

Credit Agreements

2014 Credit Agreement

In December 2014, TEP entered into an unsecured credit agreement (2014 Credit Agreement). The 2014 Credit Agreement provides for a $130 million term loan commitment and a $70 million revolving credit commitment. In January 2015, amounts borrowed under the term loan commitment were used to purchase existing Pima County, Arizona unsecured tax-exempt industrial development revenue bonds (IDBs) issued in June 2008 for the benefit of TEP in the amount of $130 million. The 2014 Credit Agreement expires in November 2015.

The 2014 Credit Agreement contains substantially the same restrictive covenants as the 2010 Credit Agreement described below. At December 31, 2014, TEP was in compliance with the terms of the 2014 Credit Agreement. See Note 5 of Notes to Consolidated Financial Statements.

At December 31, 2014, TEP had $70 million borrowings at an interest rate of 0.750% under the 2014 Credit Agreement revolving credit facility and no borrowings under the term loan portion of the 2014 Credit Agreement.

2010 Credit Agreement

The 2010 Credit Agreement consists of a $200 million revolving credit, revolving LOC facility and an $82 million LOC facility to support tax-exempt bonds. The 2010 Credit Agreement expires in November 2016.

In December 2013, TEP reduced its letter of credit facility from $186 million to $82 million, following the refinancing of $100 million of variable rate bonds and the cancellation of $104 million of LOCs supporting those bonds.

At December 31, 2014, there were $15 million in borrowings outstanding and less than $1 million of LOCs issued under the 2010 Credit Agreement.

The 2010 Credit Agreement contains restrictions on mergers and sales of assets. The 2010 Credit Agreement also requires TEP not to exceed a maximum leverage ratio. If TEP complies with the terms of the 2010 Credit Agreement, TEP may pay dividends to UNS Energy subject to the terms of the merger order issued by the ACC in August 2014. At December 31, 2014, TEP was in compliance with the terms of the 2010 Credit Agreement. See Note 5 of Notes to Consolidated Financial Statements.

2010 Reimbursement Agreement

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

In February 2014, TEP amended the 2010 Reimbursement Agreement to extend the expiration date of the LOC from 2014 to 2019.

The 2010 Reimbursement Agreement contains substantially the same restrictive covenants as the 2010 Credit Agreement described above. At December 31, 2014, TEP was in compliance with the terms of the 2010 Reimbursement Agreement.

2014 Bond Issuances and Redemptions

In March 2014, TEP issued $150 million of 5.0% unsecured notes due March 2044. TEP may redeem the notes prior to September 2043, with a make-whole premium plus accrued interest. After September 2043, TEP may redeem the notes at par plus accrued interest. TEP used the net proceeds to repay approximately $90 million on the outstanding borrowings under the 2010 Credit Agreement with the remaining proceeds used for general corporate purposes. See Note 5 of Notes to Consolidated Financial Statements.

Capital Lease Obligations

At December 31, 2014, TEP had $243 million of total capital lease obligations on its balance sheet. The table below provides a summary of the outstanding lease obligations:

Capital Leases	Capital Lease Obligation Balance As Of December 31, 2014 Millions of Dollars	Expiration	Renewal/Purchase Option
Springerville Unit 1[(1)]	$ 43	2015	Fair market value
Springerville Coal Handling Facilities	117	2015	Fixed price purchase option of $120 million[(2)]
Springerville Common Facilities[(3)]	83	2017 and 2021	Fixed price purchase option of $106 million[(3)]
Total Capital Lease Obligations	$ 243		

(1) The Springerville Unit 1 Leases cover both Unit 1 and an undivided one-half interest in certain Springerville Common Facilities. The $43 million balance represents the lease purchase options that were completed in January 2015. As of January 1, 2015 there is no capital lease obligation balance related to Springerville Unit 1.

(2) The $117 million balance represents the present value of the lease purchase options elected in April 2014. Upon TEP’s purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. See Item 7. Management's Discussion and Analysis of Financial Condition and Factors Affecting Results of Operations, Springerville Coal Handling Facilities Capital Lease Purchase Commitment. Also see Note 5 of Notes to Consolidated Financial Statements.

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

Our capital lease obligation balances decline over time as scheduled capital lease payments are made by TEP.

Contractual Obligations

The following chart displays TEP's contractual obligations by maturity and by type of obligation as of December 31, 2014:

Payment Due in Years Ending December 31,	2015	2016	2017	2018	2019	Thereafter	Other	Total
	Millions of Dollars							
Long-Term Debt								
Principal(1)	$—	$79	$—	$100	$37	$1,159	$—	$1,375
Interest(2)	58	59	59	59	56	554	—	845
Capital Lease Obligations(3)	188	16	18	11	12	18	—	263
Operating Leases:(4)								
Land Easements and Rights-of-Way	2	1	1	1	2	77	—	84
Operating Leases Other	1	1	1	1	1	5	—	10
Purchase Obligations:								
Fuel(5)	76	78	76	49	49	285	—	613
Purchased Power	22	7	—	—	—	—	—	29
Transmission	6	6	6	6	4	16	—	44
Renewable Power Purchase Agreements(6)	45	45	45	45	44	565	—	789
RES Performance-Based Incentives(7)	8	8	8	8	8	76	—	116
Acquisition of Springerville Common Facilities(8)	—	—	38	—	—	68	—	106
Other Long-Term Liabilities:(9)								
Pension & Other Post Retirement Obligations(10)	30	6	6	6	7	37	—	92
Unrecognized Tax Benefits	—	—	—	—	—	—	4	4
Total Contractual Obligations	$436	$306	$258	$286	$220	$2,860	$4	$4,370

(1) Certain of TEP's variable rate IDBs or pollution control revenue bonds are secured by LOCs issued pursuant to the 2010 Credit Agreement, which expires in 2016, and the 2010 TEP Reimbursement Agreement, which expires in 2019. Although the $115 million of variable rate bonds mature between 2022 and 2032, the above maturity reflects a redemption or repurchase of such bonds as though the LOCs terminate without replacement upon expiration of the 2010 Credit Agreement in 2016 (that supports $78 million of variable rate bonds) and the 2010 TEP Reimbursement Agreement in 2019 (that supports $37 million of variable rate bonds). Additionally, TEP's 2013 variable-rate IDBs, which mature in 2032, are subject to mandatory tender for purchase after the current five-year term and are therefore reflected as maturing in 2018. Excludes approximately $2 million of debt discount.

(2) Excludes interest on revolving credit facilities and includes interest on TEP's 2013 tax-exempt IDBs through the end of the current five-year term.

(3) Capital lease obligations include the purchase commitments for Springerville Unit 1 in January 2015 and Springerville Coal Handling Facilities at the expiration of the lease term in April 2015. Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP are reimbursing TEP for various operating costs related to the common facilities on an ongoing basis, including a total of $14 million annually related to the Springerville Common and Springerville Coal Handling Facilities Leases. TEP remains the obligor under these capital leases, and Capital Lease Obligations do not reflect any reduction associated with this reimbursement.

(4) TEP's operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates.

(5) Excludes TEP's liability for final environmental reclamation at the coal mines which supply the Navajo, San Juan and Four Corners generating stations as the timing of payment has not been determined. See Note 6 of Notes to Consolidated Financial Statements.

(6) TEP has entered into 20-year PPAs with renewable energy generation producers to comply with the RES tariff. TEP is obligated to purchase 100% of the output of these facilities. The table above includes estimated future payments based on expected power deliveries under these contracts. TEP has entered into additional long-term renewable PPAs to comply with the RES; however, TEP's obligations to accept and pay for electric power under these agreements does not begin until the facilities are operational.

(7) TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance Based Incentives (PBIs) and are paid in contractually agreed upon

intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2 of Notes to Consolidated Financial Statements.

(8) The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. Instead of extending the leases, TEP may exercise its fixed-price purchase options.

(9) Excludes asset retirement obligations expected to occur through 2066.

(10) These obligations represent TEP's expected contributions to pension plans in 2015, expected benefit payments for its unfunded Supplemental Executive Retirement Plan (SERP), and expected retiree benefit costs to cover medical and life insurance claims as determined by the plans' actuaries. Due to the significant impact that returns on plan assets and changes in discount rates might have on payment obligation amounts, other contributions are excluded beyond 2015.

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

- The 2010 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain pricing based on TEP's credit ratings. A change in TEP's credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments. A downgrade in TEP's credit ratings would not cause a restriction in TEP's ability to borrow under its revolving credit facilities.
- The 2014 Credit Agreement, the 2010 Credit Agreement, the 2010 Reimbursement Agreement, and the 2013 Covenants Agreement contain certain financial and other restrictive covenants, including a leverage test. Failure to comply with these covenants would entitle the lenders to accelerate the maturity of all amounts outstanding. At December 31, 2014, TEP was in compliance with these covenants. See Credit Agreements, above.
- TEP conducts its wholesale marketing and risk management activities under certain master agreements whereby TEP may be required to post credit enhancements in the form of cash or a LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, a change in TEP's credit ratings, or if there has been a material change in TEP's creditworthiness. As of December 31, 2014, TEP had posted less than $1 million in LOCs for credit enhancement with wholesale counterparties.
- 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.

Dividends on Common Stock

In 2014, TEP paid dividends to UNS Energy of $40 million. TEP paid dividends to UNS Energy of $40 million in 2013 and $30 million in 2012.

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

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 in 2014 and does not expect to make any payments until 2019.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with GAAP requires management to apply accounting policies and to make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements and related notes. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in

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subsequent periods. Additional information on TEP's other significant accounting policies can be found in Note 1 of Notes to Consolidated Financial Statements.

Accounting for Regulated Operations

We account for our regulated electric operations based on accounting standards that allow the actions of our regulators, the ACC and the FERC, to be reflected in our financial statements. Regulator actions may cause us to capitalize certain costs that would otherwise be included as an expense, or in Accumulated Other Comprehensive Income (AOCI), in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent expected future costs that have already been collected from customers. We evaluate regulatory assets and liabilities each period and believe future recovery or settlement is probable. Our assessment includes consideration of recent rate orders, historical regulatory treatment of similar costs, and changes in the regulatory and political environment. If management's assessment is ultimately different than actual regulatory outcomes, the impact on our results of operation, financial position, and future cash flows could be material.

At December 31, 2014, regulatory liabilities net of regulatory assets totaled $68 million at TEP. There are no current or expected proposals or changes in the regulatory environment that impact our ability to apply accounting guidance for regulated operations. If we conclude, in a future period, that our operations no longer meet the criteria in this guidance, we would reflect our regulatory pension assets in AOCI and recognize the impact of other regulatory assets and liabilities in the income statement, both of which would be material to our financial statements. See Note 2 of Notes to Consolidated Financial Statements.

Accounting for Asset Retirement Obligations

We are required to record the fair value of a liability for a legal obligation to retire a long-lived tangible asset in the period in which the liability is incurred. This includes obligations resulting from conditional future events. We incur legal obligations as a result of environmental and other governmental regulations, contractual agreements and other factors. To estimate the liability, management must use significant judgment and assumptions in: determining whether a legal obligation exists to remove assets; estimating the probability of a future event for a conditional obligation; estimating the fair value of the cost of removal; estimating when final removal will occur; and estimating the credit-adjusted risk-free interest rates to be used to discount the future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations. Beginning July 1, 2013, TEP began deferring costs associated with the majority of its legal AROs as regulatory assets because new depreciation rates approved in the 2013 TEP Rate Order include these costs. Deferred costs are amortized over the life of the underlying asset.

A liability for the fair value of a legal asset retirement obligation (ARO) is recognized in the period in which it is incurred if it can be reasonably estimated, with the offsetting associated asset retirement costs capitalized as a part of the carrying amount of the long-lived assets. The asset retirement cost is subsequently charged to depreciation expense over the useful life of the asset or lease term. Upon retirement of the asset, we will either settle the obligation for its recorded amount or incur a gain or loss if the actual costs differ from the recorded amount.

TEP identified legal obligations to retire generation plant assets specified in land leases for its jointly-owned Navajo and Four Corners generating stations. The land on which these stations reside is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases. Additionally, TEP entered into ground lease agreements with certain land owners for the installation of photovoltaic (PV) assets. The provisions of the PV ground leases require TEP to remove the PV facilities upon expiration of the leases. TEP's ARO related to the PV assets is estimated to be approximately $30 million at the retirement dates. TEP also has certain environmental obligations at the Luna, San Juan, Sundt and Springerville Generating Stations. TEP estimates that its share of the AROs to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt and Springerville environmental obligations will be approximately $164 million at the retirement dates. In December 2014, TEP purchased Gila River Unit 3 and assumed an ARO obligation. The environmental obligations related to Gila River will be approximately $4 million at the retirement date. No other legal obligations to retire generation plant assets were identified.

TEP has various transmission and distribution lines that operate under leases and rights-of-way that contain end dates and may contain site restoration clauses. TEP operates transmission and distribution lines as if they will be operated in perpetuity and would continue to be used or sold without land remediation. As such, there are no AROs for these assets.

The total net present value of TEP's ARO liability was $28 million at December 31, 2014. ARO liabilities are reported in Deferred Credits and Other Liabilities—Other on the balance sheet. See Note 3 of Notes to Consolidated Financial Statements.

Additionally, the authorized depreciation rates for TEP include a component designed to accrue the future costs of retiring assets for which no legal obligations exist. The accumulated balances at December 31, 2014 represent non-legal asset retirement obligation accruals, less actual removal costs incurred, net of salvage proceeds realized, and are included in Deferred Credits and Other Liabilities, Regulatory Liabilities – Noncurrent on the balance sheet. See Note 2 of Notes to Consolidated Financial Statements.

Pension and Other Retiree Benefit Plan Assumptions

TEP records plan assets, obligations, and expenses related to pension and other retiree benefit plans based on actuarial valuations, which include key assumptions on discount rates, expected returns on plan assets, compensation increases, and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally recorded or amortized over future periods. We believe that the assumptions used in recording obligations are reasonable based on prior experience, market conditions, and the advice of plan actuaries. Note 8 of Notes to Consolidated Financial Statements discusses the assumptions used in the calculation of pension plan and other retiree plan obligations.

TEP is required to recognize the underfunded status of its defined benefit pension and other retiree plans as a liability. The underfunded status is the difference between the fair value of the plans assets and the projected benefit obligation for pension plans or accumulated retiree benefit obligation for other retiree benefit plans. As the funded status, discount rates, and actuarial facts change, the liability will vary significantly in future years. TEP records the underfunded amount for its pension and other retiree obligations as a liability and a regulatory asset to reflect expected recovery of pension and other retiree obligations through the rates charged to retail customers.

At December 31, 2014, TEP discounted its future pension plan obligations at between 4.1% and 4.2% and its other retiree plan obligations at a rate of 3.9%. The discount rate for future pension plan and other retiree plan obligations is determined annually based on the rates currently available on high-quality, non-callable, long-term bonds. The discount rate is based on a corporate yield curve using an average yield between the 60th and 90th percentile of AA-graded U.S. corporate bonds with future cash flows that match the timing and amount of expected future benefit payments. For TEP’s pension plans, a 25-basis point change in the discount rate would increase or decrease the Projected Benefit Obligation (PBO) by approximately $14 million and the plan expense by $1 million. For TEP’s other retiree benefit plan, a 25-basis point change in the discount rate would increase or decrease the Accumulated Postretirement Benefit Obligation (APBO) by approximately $2 million and increase or decrease plan expense by less than $0.5 million.

TEP calculates the market-related value of pension plan assets using the fair value of the assets on the measurement date. TEP assumed that its pension plans’ assets would generate a long-term rate of return of 7% at December 31, 2014. In establishing its assumption as to the expected return on assets, TEP reviews the asset allocation and develops return assumptions for each asset class based on advice from an investment consultant and the pension’s actuary that includes both historical performance analysis and forward-looking views of the financial markets. Pension expense decreases as the expected rate of return on assets increases. A 25-basis point change in the expected return on assets would impact pension expense in 2014 by $1 million.

TEP selected the RP-2000 mortality table projected with Scale BB to measure December 31, 2014 pension obligations, whereas Scale AA was utilized for the December 31, 2013 measurement. TEP moved to Scale BB because Scale AA has lagged general US mortality since 2000. The longer life expectancy assumption results in a greater obligation and expense.

TEP used a current year health care cost trend rate of 6.7% in valuing its retiree benefit obligation at December 31, 2014. This rate reflects both market conditions and historical experience. Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage point change in assumed health care cost trend rates would change the retiree benefit obligation by an approximately $7 million increase or $6 million decrease and change the related 2015 plan expense by $1 million.

In 2015, TEP will incur pension costs of approximately $13 million and other retiree benefit costs of approximately $6 million. TEP expects to charge approximately $14 million of these costs to O&M expense, $4 million to capital, and $1 million to Other Expense. TEP expects to make pension plan contributions of $23 million in 2015. In 2009, TEP established a VEBA trust to fund its other retiree benefit plan. In 2015, TEP expects to make benefit payments to retirees under the retiree benefit plan of approximately $5 million and contributions to the VEBA trust of approximately $3 million, net of distributions.

Accounting for Derivative Instruments and Hedging Activities

Commodity Derivative Contracts

TEP enters into forward contracts to purchase or sell capacity or energy at contract prices over a given period of time, typically for one month, three months, or one year, within established limits to meet forecasted load requirements or to take advantage of favorable market opportunities. In general, TEP enters into forward purchase contracts when market conditions provide the opportunity to purchase energy for its load at prices that are below the marginal cost of its supply resources or to supplement its own resources (e.g., during plant outages and summer peaking periods). TEP enters into forward sales contracts when it forecasts that it has excess supply and the market price of energy exceeds its marginal cost. TEP enters into forward gas commodity price swap agreements to lock in fixed prices on a portion of forecasted gas purchases and to hedge the price risk associated with forward PPAs that are indexed to natural gas prices.

For all commodity derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the consolidated balance sheets and measure those instruments at fair value. Unrealized gains and losses on commodity derivative contracts entered into for retail customer load are recorded as either a regulatory asset or regulatory liability on the balance sheet of TEP based on our ability to recover the costs of hedging activities entered into to mitigate energy price risk for retail customers. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets through the PPFAC mechanism.

The market prices used to determine fair values for TEP’s derivative instruments at December 31, 2014, are estimated based on various factors including broker quotes, exchange prices, over the counter prices, and time value.

TEP manages the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using a standardized agreement, which allows for the netting of current period exposures to and from a single counterparty.

Long-Term Power Sale Option

TEP entered into a three-year option to sell power to a long-term wholesale customer. This contract is not subject to regulatory accounting. Unrealized gains or losses are recorded through the income statement in Electric Wholesale Sales.

Commodity Cash Flow Hedge

TEP hedges the cash flow risk associated with a six-year power wholesale supply agreement using a six-year power purchase swap agreement. Unrealized gains and losses are recorded in AOCI. See Item 7A. Quantitative and Qualitative Disclosures about Market Risk, Commodity Price Risk and Note 1of Notes to Consolidated Financial Statements.

Interest Rate Swaps

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates tied to LIBOR on the Springerville Common Facilities Lease. As of December 31, 2014, approximately $32 million of variable rate lease debt for the Springerville Common Facilities Lease had been hedged through an interest rate swap agreement through January 2, 2020.

Revenue Recognition

TEP’s retail revenues, which are recognized in the period that electricity is delivered and consumed by customers, include unbilled revenue based on an estimate of kWh delivered at the end of each period. Unbilled revenues are dependent upon a number of factors that require management’s judgment including estimates of retail sales and customer usage patterns. The unbilled revenue is estimated by comparing the estimated kWh delivered to the kWh billed to our retail customers. The excess of estimated kWh delivered over kWh billed is then allocated to the retail customer classes based on estimated usage by each customer class. We then record revenue for each customer class based on the various Retail Rates for each customer class. Due to the seasonal fluctuations of TEP’s actual load, the unbilled revenue amount increases during the spring and summer and decreases during the fall and winter. A provision for uncollectible accounts is recorded as a component of O&M expense.

Plant Asset Depreciable Lives

TEP has significant investments in electric generation assets and electric transmission and distribution assets. We calculate depreciation expense based on our estimate of the useful lives of our plant assets and expected net removal costs. The useful lives of plant assets are further detailed in Note 5 of Notes to Consolidated Financial Statements. Changes to depreciation estimates resulting from a change of estimated service life or removal costs could have a significant impact on the amount of depreciation expense recorded in the income statement. The ACC approves depreciation rates for all generation and distribution assets. Depreciation rates for such assets cannot be changed without the ACC's approval. TEP's transmission assets are subject to the jurisdiction of the FERC. See Note 1 of Notes to Consolidated Financial Statements.

The 2013 TEP Rate Order approved a change in authorized depreciation rates for generation and distribution plant from an average of 3.32% to 3.00%, effective July 1, 2013. The reduction in depreciation rates was primarily due to revised estimates of removal costs, net of estimated salvage value for interim and final retirements. See Note 2 of Notes to Consolidated Financial Statements.

Income Taxes

Due to the differences between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. We account for this difference by recording deferred income tax assets and liabilities using the effective income tax rate at our balance sheet date.

Income tax liabilities are allocated to TEP based on TEP's taxable income and deductions as reported in the FortisUS, Inc. consolidated tax return.

A valuation allowance is established against deferred tax assets for which management believes it is more likely than not that the deferred asset will not be realized. In making this judgment, management evaluates all available evidence and gives more weight to objective verifiable evidence. At December 31, 2014, TEP had a $2 million valuation allowance. See Note 11 of Notes to Consolidated Financial Statements.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

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

See Forward-Looking Information.

Risk Management Committee

We have a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to the wholesale energy marketing and power procurement activities of TEP. Our Risk Management Committee, which meets on a quarterly basis and as needed, consists of officers from the finance, accounting, legal, wholesale marketing, and generation operations departments of TEP. To limit TEP’s exposure to commodity price risk, the Risk Management Committee sets trading and hedging policies and limits, which are reviewed frequently to respond to constantly changing market conditions. To limit

TEP’s exposure to credit risk, the Risk Management Committee reviews counterparty credit exposure as well as credit policies and limits.

Interest Rate Risk

Long-Term Debt

TEP is exposed to interest rate risk resulting from changes in interest rates on certain of its variable rate debt obligations. TEP had $215 million at December 31, 2014 in tax-exempt variable rate debt outstanding. The interest rates on TEP’s tax-exempt variable rate debt are reset weekly or monthly. The average rate on TEP's weekly variable rate debt (including letter of credit fees and remarketing fees) was 1.46% in 2014 and 1.59% in 2013. The average weekly interest rate ranged from 1.4% to 1.75% in 2014 and 1.43% to 1.78% during 2013. The average monthly rate on TEP’s monthly variable rate debt (issued in November 2013 and based on a percentage of an index equal to one-month LIBOR plus a bank margin rate) was 0.87% in 2014. The rates ranged from 0.85% to 0.95% in 2014. Although short-term interest rates were low and stable in 2014 and 2013, TEP may still be subject to volatility in its tax-exempt variable rate debt. A 100 basis point increase in average interest rates on this debt, over a twelve month period, would result in a decrease in TEP’s pre-tax net income of approximately $2 million.

TEP can manage its exposure to variable interest rate risk by entering into interest rate swaps and financing transactions to rebalance its mix of variable rate and fixed rate long-term debt. TEP has a fixed-for-floating interest rate swap in place to hedge floating rate interest rate risk associated with a portion of its Springerville Common Facilities lease debt. The notional amount of the swap is $32 million at December 31, 2014. The notional amount of lease debt that was unhedged as of December 31, 2014 was $18 million. TEP did not have any other interest rate swaps at December 31, 2014.

Interest Rate Swaps

To adjust the value of TEP’s interest rate swaps, classified as cash flow hedges, to fair value in Other Comprehensive Income (Loss), TEP recorded the following net unrealized gains:

	2014	2013	2012
	Millions of Dollars		
Unrealized Gains (Losses)	$2	$4	$2

Revolving Credit Facilities

TEP is subject to interest rate risk resulting from changes in interest rates on borrowings under its credit agreements. The interest paid on borrowings is variable. Revolving credit borrowings may be made on the basis of a spread over LIBOR or an Alternate Base Rate. As a result, TEP may experience significant volatility in the rates paid on LIBOR borrowings under its revolving credit facilities.

Marketable Securities Risk

The majority of TEP’s pension plan assets, as well as assets associated with other employee benefit obligations, are investments in equity and debt securities. These investments are exposed to price fluctuations in equity markets and changes in interest rates. Of the assets held for employee benefit obligations, the pension plan assets comprise the largest portion. The pension plan assets will help fund defined retirement benefits for substantially all of our employees. Declines in the values of these assets could increase required employer contributions, which would adversely affect cash flows. Declines in values could also increase the reported pension expense, adversely affecting TEP’s results of operations.

Commodity Price Risk

TEP is exposed to commodity price risk primarily relating to changes in the market price of electricity, natural gas, and coal. This risk is mitigated through hedging practices and a PPFAC mechanism which fully recovers the actual retail fuel and purchased power costs incurred on a timely basis from TEP’s retail customers. The PPFAC mechanism has a forward component and a true-up component. The forward component of the PPFAC rate is based on forecasted fuel and purchased power costs. The true-up component reconciles actual fuel and purchased power costs with the amounts collected in the prior year and any amounts under/over-collected will be collected from/credited to customers. If the actual price of power is higher than the forecasted PPFAC rate, TEP's operating cash flows are reduced by the price difference until the subsequent 12-month period when the true-up component is adjusted to allow the recovery of this difference.

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Purchases and Sales of Energy

To manage its exposure to energy price risk, TEP enters into forward contracts to buy or sell energy at a specified price and future delivery period. Generally, TEP commits to future sales based on expected excess generating capability, forward prices and generation costs, using a diversified market approach to provide a balance between long-term, mid-term, and spot energy sales. TEP generally enters into forward purchases during its summer peaking period to ensure it can meet its load and reserve requirements, and account for other contracts and resource contingencies. TEP also enters into limited forward purchases and sales to optimize its resource portfolio and take advantage of geographical differences in price. These positions are managed on both a volumetric and dollar basis and are closely monitored using risk management policies and procedures overseen by the Risk Management Committee. For example, the risk management policies provide that TEP should not take a short physical position in the third quarter and must have owned generation backing up all physical forward sales positions at the time the sale is made. TEP's risk management policies also place limits on the duration of transactions in both gas and power.

TEP enters into some forward contracts considered to be normal purchases and sales of electric energy and are therefore not accounted for as derivatives. TEP records revenues on its "normal sales" and expenses on its "normal purchases" in the period in which the energy is delivered. TEP also enters into forward contracts that are not considered to be "normal purchases and sales" and therefore are accounted for as derivatives. When TEP has derivative forward contracts, it marks them to market using actively quoted prices obtained from brokers for power traded over-the-counter at Palo Verde and at other southwestern U.S. trading hubs. TEP believes that these broker quotations used to calculate the mark-to-market values represent accurate measures of the fair values of TEP's positions because of the short-term nature of TEP's positions, as limited by risk management policies, and the liquidity in the short-term market.

Long-Term Wholesale Sales

TEP has several long-term wholesale agreements for the sale of energy. Sales under some of these agreements are based on indexed energy prices. Changes in the price of power affect TEP's revenue and income from these agreements. One such agreement with SRP requires SRP to purchase 500,000 MWh of on-peak energy per year from TEP through the end of the contract in May 2016. SRP does not pay a demand charge and the price of energy is based on a discount to the price of on-peak power on the Palo Verde Market Index. Each $5 change in the per MWh market price of on-peak power can affect annual pre-tax income by approximately $3 million.

Natural Gas

TEP is also subject to commodity price risk from changes in the price of natural gas. In addition to energy from its coal-fired facilities, TEP typically uses power purchases, supplemented by generation from its gas-fired units to meet the summer peak demands of its retail customers and to meet local reliability needs. Some of these purchased power contracts are indexed to natural gas prices. Short-term and spot power purchase prices are also closely correlated to natural gas prices. Due to its increasing gas and purchased power usage, TEP hedges a portion of its total natural gas exposure from plant fuel, gas-indexed power purchases, and spot market purchases with various instruments up to three years in advance. TEP purchases its remaining gas fuel and power needs in the spot and short-term markets.

As required by fair value accounting rules, for the year ended December 31, 2014, TEP considered the impact of non-performance risk in the measurement of fair value of its derivative assets and derivative liabilities net of collateral posted.

To adjust the value of its commodity derivatives to fair value in regulatory assets or regulatory liabilities, TEP recorded the following net unrealized gains (losses):

	2014	2013	2012
	Millions of Dollars		
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets)/Liabilities	$(18)	$—	$6

The chart below displays the valuation methodologies and maturities of TEP's power and gas derivative contracts.

	Unrealized Gain (Loss) of TEP's Hedging Activities			
Source of Fair Value at December 31, 2014	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized

				Gain (Loss)
	Millions of Dollars			
Prices Actively Quoted	$(4)	$(11)	$(3)	$(18)

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Sensitivity Analysis of Derivatives

TEP uses sensitivity analysis to measure the impact of favorable and unfavorable changes in market prices on the fair value of its derivative forward contracts. TEP records unrealized gains and losses as either a regulatory asset or regulatory liability. As contracts settle, the unrealized gains and losses are reversed and realized gains or losses are recorded to the PPFAC. For TEP's non-cash flow power hedges, a 10% change in the market price of power would affect unrealized positions reported as a regulatory asset or regulatory liability by approximately $2 million; for gas swaps and collars contracts, a 10% change in the market price of energy would affect unrealized positions reported as a regulatory asset or liability by approximately $4 million.

Coal

TEP is subject to commodity price risk from changes in the price of coal used to fuel its coal-fired generating plants. This risk is mitigated through a PPFAC mechanism which allows for the recovery of costs from retail customers.
TEP's coal supply contract for Springerville Units 1 and 2 expires in 2020. TEP expects coal reserves to be sufficient to supply the estimated requirements for Units 1 and 2 for their presently estimated remaining lives. The coal price is determined by the cost of Powder River Basin coal delivered to Springerville Unit 3 subject to a floor and ceiling.
While TEP has an existing coal inventory, we do not have a long-term coal supply contract for Sundt Unit 4. Prior to 2010, Sundt Unit 4 was predominantly fueled by coal; however, the generating station can also be operated with natural gas. Since 2010, TEP has fueled Sundt Unit 4 with both coal and natural gas depending on which resource is most economic.

TEP participates in jointly-owned generating facilities at Four Corners, Navajo, and San Juan, where coal supplies are received under contracts administered by the operating agents. The coal contracts at Four Corners and Navajo expire in 2031 and 2019, respectively. The current coal supply contract for San Juan expires on December 31, 2017. TEP and other San Juan owners are currently negotiating agreements concerning the future San Juan fuel supply. If the Participants are unable to negotiate an economic fuel supply, the continued operation of San Juan could be jeopardized resulting in the retirement of San Juan Unit 1 earlier than expected.

The contracts to purchase coal for use at the jointly-owned facilities require TEP to purchase minimum amounts of coal at an estimated average annual cost of $31 million for the next three years and $19 million thereafter through 2031. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources, Contractual Obligations and Note 6 of Notes to Consolidated Financial Statements.

Credit Risk

TEP is exposed to credit risk in its energy-related marketing activities related to potential non-performance by counterparties. We manage the risk of counterparty default by performing financial credit reviews, setting limits, monitoring exposures, requiring collateral when needed, and using standard agreements which allow for the netting of current period exposures to and from a single counterparty. We calculate counterparty credit exposure by adding any outstanding receivable (net of amounts payable if a netting agreement exists) to the mark-to-market value of any forward contracts. If exposure exceeds credit limits or contractual collateral thresholds, we may request that a counterparty provide credit enhancement in the form of cash collateral or a letter of credit.

TEP has entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through five years. As of December 31, 2014, the credit exposure to TEP from financial institution counterparties was less than $1.7 million.

As of December 31, 2014, TEP’s total credit exposure related to its wholesale marketing and gas hedging activities was approximately $12 million. TEP had one non-investment grade counterparty with exposure of greater than 10% of its total credit exposure. TEP’s total exposure to non-investment grade counterparties was $1 million.

At December 31, 2014, TEP posted no cash collateral and less than $1 million in LOCs as credit enhancements with its counterparties, and did not hold any collateral from its counterparties.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Controls Over Financial Reporting

TEP's management is responsible for establishing and maintaining adequate internal control over financial reporting. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of TEP's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the 2013 COSO Internal Control – Integrated Framework.

Based on management's assessment using those criteria, management has concluded that, as of December 31, 2014, TEP's internal control over financial reporting was effective.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Tucson Electric Power Company:

We have audited the accompanying consolidated balance sheet of Tucson Electric Power Company and subsidiaries as of December 31, 2014, and the related consolidated statements of income, comprehensive income, capitalization, stockholder’s equity and cash flows for the year then ended. Our audit also included the financial statement schedules as at December 31, 2014 and for the year then ended listed in the Index at Item 15(a)(1) and 15(a)(2). These financial statements and schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedules based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company’s internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provided a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Tucson Electric Power Company and subsidiaries at December 31, 2014, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedules, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Ernst & Young LLP

Ernst & Young LLP

Calgary, Canada

02/19/15

Report of Independent Registered Public Accounting Firm
To the Board of Directors and Stockholder of
Tucson Electric Power Company:
In our opinion, the consolidated balance sheet and statement of capitalization as of December 31, 2013 and the related consolidated statements of income, comprehensive income, cash flows, and changes in stockholder's equity for each of the two years in the period ended December 31, 2013 present fairly, in all material respects, the financial position of Tucson Electric Power Company and its subsidiaries at December 31, 2013, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for each of the two years in the period ended December 31, 2013 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers
LLP
PricewaterhouseCoopers LLP
Phoenix, Arizona
February 25, 2014, except for the effects of the revision discussed in Note 1 to the consolidated financial statements, as to which the date is August 14, 2014

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2014	2013	2012
	Thousands of Dollars		
Operating Revenues			
Electric Retail Sales	$970,145	$934,357	$915,879
Electric Wholesale Sales	158,323	132,500	111,194
Other Revenues	141,433	129,833	134,587
Total Operating Revenues	1,269,901	1,196,690	1,161,660
Operating Expenses			
Fuel	297,537	325,903	318,901
Purchased Power	152,922	112,452	80,137
Transmission and Other PPFAC Recoverable Costs	18,179	12,233	5,722
Increase (Decrease) to Reflect PPFAC Recovery Treatment	(11,194)	(12,458)	31,113
Total Fuel and Purchased Energy	457,444	438,130	435,873
Operations and Maintenance	378,877	335,321	334,553
Depreciation	126,520	118,076	110,931
Amortization	28,567	31,294	39,493
Taxes Other Than Income Taxes	47,805	43,498	40,323
Total Operating Expenses	1,039,213	966,319	961,173
Operating Income	230,688	230,371	200,487
Other Income (Deductions)			
Interest Income	208	120	136
Other Income	8,598	5,770	3,953
Other Expense	(12,735)	(10,715)	(13,574)
Appreciation in Fair Value of Investments	1,371	2,833	1,892
Total Other Income (Deductions)	(2,558)	(1,992)	(7,593)
Interest Expense			
Long-Term Debt	60,577	56,378	55,038
Capital Leases	10,249	25,140	33,613
Other Interest Expense	810	87	1,446
Interest Capitalized	(3,755)	(2,554)	(1,782)
Total Interest Expense	67,881	79,051	88,315
Income Before Income Taxes	160,249	149,328	104,579
Income Tax Expense	57,911	47,986	39,109
Net Income	$102,338	$101,342	$65,470

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2014	2013	2012
	Thousands of Dollars		
Comprehensive Income			
Net Income	$102,338	$101,342	$65,470
Other Comprehensive Income			
Net Changes in Fair Value of Cash Flow Hedges, net of income tax (expense) benefit of $(1,140), $(1,793), and $(887).	1,675	2,738	1,354
Supplemental Executive Retirement Plan (SERP) Net Unrealized Loss and Prior Service Cost, net of income tax (expense) benefit of $1,068, $(572), and $608.	(1,725)	916	(840)
Total Other Comprehensive Income (Loss), Net of Taxes	(50)	3,654	514
Total Comprehensive Income	$102,288	$104,996	$65,984

See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
	Thousands of Dollars		
Net Income	$102,338	$101,342	$65,470
Adjustments to Reconcile Net Income			
To Net Cash Flows from Operating Activities			
Depreciation Expense	126,520	118,076	110,931
Amortization Expense	28,567	31,294	39,493
Amortization of Deferred Debt-Related Costs included in Interest Expense	2,626	2,452	2,227
Use of Renewable Energy Credits for Compliance	17,818	15,990	5,071
Deferred Income Taxes	62,609	59,199	45,232
Pension and Retiree Expense	13,648	19,878	19,289
Pension and Retiree Funding	(14,388)	(27,636)	(25,899)
Share-Based Compensation Expense	5,010	2,709	2,029
Allowance for Equity Funds Used During Construction	(6,677)	(4,526)	(2,840)
LFCR Revenue	(11,327)	(2,171)	—
Increase (Decrease) to Reflect PPFAC Recovery	(11,194)	(12,458)	31,113
Fortis Acquisition Direct Customer Benefit	18,870	—	—
PPFAC Reduction - 2013 TEP Rate Order	—	3,000	—
Changes in Assets and Liabilities which Provided (Used)			
Cash Exclusive of Changes Shown Separately			
Accounts Receivable	(14,599)	(6,041)	(871)
Materials and Fuel Inventory	666	16,145	(38,384)
Accounts Payable	10,712	334	1,115
Interest Accrued	(377)	4,859	8,055
Taxes Other Than Income Taxes	1,625	1,425	905
Current Regulatory Liabilities	8,388	3,331	(3,040)
Other	(27,172)	18,989	8,023
Net Cash Flows – Operating Activities	313,663	346,191	267,919
Cash Flows from Investing Activities			
Capital Expenditures	(323,524)	(252,848)	(252,782)
Purchase of Gila River Unit 3	(163,938)	—	—
Purchase of Springerville Unit 1 Lease Assets	(19,608)	—	—
Purchase of Intangibles—Renewable Energy Credits	(28,334)	(23,280)	(8,889)
Return of Investments in Springerville Lease Debt	—	9,104	19,278
Contributions in Aid of Construction	15,903	3,959	9,982
Other, net	1,863	3,403	4,530
Net Cash Flows—Investing Activities	(517,638)	(259,662)	(227,881)
Cash Flows from Financing Activities			
Proceeds from Borrowings Under Revolving Credit Facilities	275,000	78,000	189,000
Repayments of Borrowings Under Revolving Credit Facilities	(190,000)	(78,000)	(199,000)
Proceeds from Issuance of Long-Term Debt	149,168	—	149,513
Payments of Capital Lease Obligations	(165,145)	(99,621)	(89,452)
Dividends Paid to UNS Energy	(40,000)	(40,000)	(30,000)
Repayments of Long-Term Debt	—	—	(6,535)
Payment of Debt Issue/Retirement Costs	(1,856)	(1,865)	(3,547)
Equity Investment from UNS Energy	225,000	—	—
Other, net	643	549	2,008

Net Cash Flows—Financing Activities	252,810	(140,937)	11,987
Net Increase (Decrease) in Cash and Cash Equivalents	48,835	(54,408)	52,025
Cash and Cash Equivalents, Beginning of Year	25,335	79,743	27,718
Cash and Cash Equivalents, End of Year	$74,170	$25,335	$79,743

See Note 9 of Notes to Consolidated Financial Statements for supplemental cash flow information.
See Notes to Consolidated Financial Statements.

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	2013
	Thousands of Dollars	
ASSETS		
Utility Plant		
Plant in Service	$5,175,148	$4,467,667
Utility Plant Under Capital Leases	667,157	637,957
Construction Work in Progress	109,070	180,485
Total Utility Plant	5,951,375	5,286,109
Less Accumulated Depreciation and Amortization	(2,052,216)	(1,826,977)
Less Accumulated Amortization of Capital Lease Assets	(473,969)	(514,677)
Total Utility Plant—Net	3,425,190	2,944,455
Investments and Other Property		
Investments in Lease Equity	—	36,194
Other	37,599	33,488
Total Investments and Other Property	37,599	69,682
Current Assets		
Cash and Cash Equivalents	74,170	25,335
Accounts Receivable—Customer	93,521	80,211
Unbilled Accounts Receivable	36,804	34,369
Allowance for Doubtful Accounts	(4,885)	(4,825)
Accounts Receivable—Due from Affiliates	5,382	6,064
Materials and Supplies	86,750	75,200
Deferred Income Taxes—Current	102,006	70,722
Fuel Inventory	36,368	44,027
Regulatory Assets—Current	69,383	42,555
Derivative Instruments	1,633	2,137
Other	22,848	12,923
Total Current Assets	523,980	388,718
Regulatory and Other Assets		
Regulatory Assets—Noncurrent	223,192	141,030
Derivative Instruments	300	167
Other Assets	22,161	19,233
Total Regulatory and Other Assets	245,653	160,430
Total Assets	$4,232,422	$3,563,285

See Notes to Consolidated Financial Statements.
(Continued)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	2013
	Thousands of Dollars	
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity	$1,215,779	$925,923
Capital Lease Obligations	69,438	131,370
Long-Term Debt	1,372,414	1,223,070
Total Capitalization	2,657,631	2,280,363
Current Liabilities		
Current Obligations Under Capital Leases	173,822	186,056
Borrowings Under Revolving Credit Facilities	85,000	—
Accounts Payable—Trade	110,480	88,556
Accounts Payable—Due to Affiliates	2,933	9,153
Accrued Taxes Other than Income Taxes	36,110	34,485
Accrued Employee Expenses	15,679	24,454
Regulatory Liabilities—Current	38,847	23,701
Accrued Interest	21,021	22,785
Customer Deposits	20,339	21,354
Derivative Instruments	18,874	5,531
Other	9,673	9,244
Total Current Liabilities	532,778	425,319
Deferred Credits and Other Liabilities		
Deferred Income Taxes—Noncurrent	491,546	428,103
Regulatory Liabilities—Noncurrent	321,186	263,270
Pension and Other Postretirement Benefits	138,319	84,936
Derivative Instruments	6,288	5,161
Other	84,674	76,133
Total Deferred Credits and Other Liabilities	1,042,013	857,603
Commitments, Contingencies & Environmental Matters (Note 6)		
Total Capitalization and Other Liabilities	$4,232,422	$3,563,285

See Notes to Consolidated Financial Statements.
(Concluded)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

			December 31, 2014	2013
			Thousands of Dollars	
COMMON STOCK EQUITY				
Common Stock-No Par Value			$1,116,539	$888,971
	2014	2013		
Shares Authorized	75,000,000	75,000,000		
Shares Outstanding	32,139,434	32,139,434		
Capital Stock Expense			(6,357)	(6,357)
Accumulated Earnings			111,523	49,185
Accumulated Other Comprehensive Loss			(5,926)	(5,876)
Total Common Stock Equity			1,215,779	925,923
PREFERRED STOCK				
No Par Value, 1,000,000 Shares Authorized, None Outstanding			—	—
CAPITAL LEASE OBLIGATIONS				
Springerville Unit 1			42,925	192,871
Springerville Coal Handling Facilities			117,573	27,878
Springerville Common Facilities			82,762	96,677
Total Capital Lease Obligations			243,260	317,426
Less Current Maturities			173,822	186,056
Total Long-Term Capital Lease Obligations			69,438	131,370
LONG-TERM DEBT				
	Maturity	Interest Rate		
Variable Rate Bonds	2022 - 2032	Variable	214,830	214,802
Fixed Rate Bonds	2020 - 2044	3.85% – 5.75%	1,157,584	1,008,268
Total Long-Term Debt			1,372,414	1,223,070
Total Capitalization			$2,657,631	$2,280,363

See Notes to Consolidated Financial Statements.

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

	Common Stock	Capital Stock Expense	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
	Thousands of Dollars				
Balances at December 31, 2011	$888,971	$(6,357)	$(47,627)	$ (10,044)	$824,943
Net Income			65,470		65,470
Other Comprehensive Loss, net of tax				514	514
Dividends Declared			(30,000)		(30,000)
Balances at December 31, 2012	888,971	(6,357)	(12,157)	(9,530)	860,927
Net Income			101,342		101,342
Other Comprehensive Income, net of tax				3,654	3,654
Dividends Declared			(40,000)		(40,000)
Balances at December 31, 2013	888,971	(6,357)	49,185	(5,876)	925,923
Net Income			102,338		102,338
Other Comprehensive Income, net of tax				(50)	(50)
Dividends Declared			(40,000)		(40,000)
Contribution from Parent	225,000				225,000
Other	2,568				2,568
Balances at December 31, 2014	$1,116,539	$(6,357)	$111,523	$ (5,926)	$1,215,779

See Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND FINANCIAL STATEMENT PRESENTATION

Tucson Electric Power Company (TEP) is a regulated utility that generates, transmits and distributes electricity to approximately 415,000 retail electric customers in a 1,155 square mile area in southeastern Arizona. TEP also sells electricity to other utilities and power marketing entities, located primarily in the western United States. TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis), which is a leader in the North American electric and gas utility business.

FORTIS ACQUISITION OF UNS ENERGY

UNS Energy, the parent of TEP, was acquired by Fortis for $60.25 per share of UNS Energy common stock in cash effective August 15, 2014.

The Arizona Corporation Commission's (ACC) approval was subject to certain stipulations, including, but not limited to, the following:

- TEP will provide credits on retail customers' bills totaling approximately $19 million over five years: $6 million in year one and $3 million annually in years two through five. The monthly bill credits will be applied each year from October through March effective October 1, 2014;
- Dividends paid from TEP to UNS Energy cannot exceed 60 percent of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reaches 50 percent of total capital; and
- Fortis making an equity investment of at least $220 million to UNS Energy and its regulated subsidiaries, including TEP. Fortis exceeded the investment requirement by contributing $287 million to UNS Energy through December 31, 2014. UNS Energy then contributed $225 million to TEP.

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

Completion of the Merger resulted in accelerated vesting and expense recognition of all outstanding non-vested UNS Energy share-based awards that would otherwise have been recognized over remaining vesting periods through February 2017. TEP recognized approximately $2 million of expense in 2014 due to the accelerated vesting of the awards. TEP recorded total share-based compensation expense of $5 million for the year ended December 31, 2014, $3 million for the year ended December 31, 2013, and $2 million for the year ended December 31, 2012. In August 2014, UNS Energy settled all outstanding share-based compensation awards in cash.

BASIS OF PRESENTATION

TEP's consolidated financial statements and disclosures are presented in accordance with generally accepted accounting principles (GAAP) in the United States which includes specific accounting guidance for regulated operations. See Note 2 of Notes to Consolidated Financial Statements. The 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 non-affiliated entities. TEP's proportionate share of jointly owned facilities is recorded as Utility Plant on the consolidated balance sheets, and our proportionate share of the operating costs associated with these facilities is included in the consolidated statements of income. See Note 3 of Notes to Consolidated Financial Statements.

TEP did not reflect the impacts of acquisition accounting in its financial statements. All adjustments of assets and liabilities to fair value and the resultant goodwill associated with the Merger were recorded by FortisUS Inc., a wholly owned subsidiary of Fortis.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

REVISION OF BALANCE SHEET AND STATEMENT OF CAPITALIZATION AS OF DECEMBER 31, 2013

TEP revised its December 31, 2013 balance sheet and statement of capitalization to correct an immaterial error in the classification of capital lease obligations and related deferred income taxes. The correction increased current capital lease obligations and decreased noncurrent capital lease obligations by $18 million and increased current deferred tax assets and noncurrent deferred tax liabilities by $7 million. The notes that follow have been updated for this revision.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In 2014, we adopted accounting guidance that:

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

USE OF ACCOUNTING ESTIMATES

Management uses estimates and assumptions when preparing financial statements under GAAP. These estimates and assumptions affect:

- Assets and liabilities on our balance sheets at the dates of the financial statements;
- Our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- Our revenues and expenses in our income statements during the periods presented.

Because these estimates involve judgments based upon our evaluation of relevant facts and circumstances, actual results may differ from the estimates.

ACCOUNTING FOR REGULATED OPERATIONS

We apply accounting standards that recognize the economic effects of rate regulation. As a result, we capitalize certain costs that would be recorded as expense or in Accumulated Other Comprehensive Income (AOCI) by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in the rates charged to retail customers or to wholesale customers through transmission tariffs. Regulatory liabilities generally represent expected future costs that have already been collected from customers or items that are expected to be returned to customers through future rate reductions.

Estimates of recovering deferred costs and returning deferred credits are based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are amortized consistent with the treatment in the rate setting process. We evaluate regulatory assets each period and believe recovery is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge to current period earnings or AOCI. See Note 2 of Notes to Consolidated Financial Statements.

TEP applies regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise’s costs of providing service; and
- Rates are set at levels that will recover the entity’s costs and can be charged to and collected from customers.

CASH AND CASH EQUIVALENTS

We consider all highly liquid investments with a remaining maturity of three months or less at acquisition to be cash equivalents.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

RESTRICTED CASH

Cash balances that are restricted regarding withdrawal or usage based on contractual or regulatory considerations are reported in Investments and Other Property—Other on the balance sheets. Restricted cash was $2 million at December 31, 2014 and December 31, 2013.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. We report utility plant at original cost. Original cost includes materials and labor, contractor services, construction overhead (when applicable), and an Allowance for Funds Used During Construction (AFUDC), less contributions in aid of construction.

We record the cost of repairs and maintenance, including planned major overhauls, to Operations and Maintenance (O&M) expense in the income statement as costs are incurred.

When a unit of regulated property is retired, we reduce accumulated depreciation by the original cost plus removal costs less any salvage value. There is no income statement impact.

AFUDC and Capitalized Interest

AFUDC reflects the cost of debt and equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts are capitalized and amortized through depreciation expense as a recoverable cost in Retail Rates. For operations that do not apply regulatory accounting, we capitalize interest related only to debt as a cost of construction. The capitalized interest that relates to debt is recorded as a reduction in Interest Expense in the income statement. The capitalized cost for equity funds is recorded as Other Income in the income statement.

The average AFUDC rates on regulated construction expenditures are included in the table below:

	2014	2013	2012
Average AFUDC Rates	7.30 %	7.38 %	7.22 %

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 2 and Note 3 of Notes to Consolidated Financial Statements. The ACC approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs. Below are the summarized average annual depreciation rates for all utility plant:

	2014	2013	2012
Average Annual Depreciation Rates	2.99 %	3.16 %	3.22 %

Utility Plant Under Capital Leases

TEP financed the following generation assets with capital leases: Springerville Unit 1; facilities at Springerville used in common with Springerville Unit 1 and Unit 2 (Springerville Common Facilities); and the Springerville Coal Handling Facilities. The capital lease expense incurred consists of Amortization Expense (see Note 3 of Notes to Consolidated Financial Statements) and Interest Expense—Capital Leases. The lease terms are described in Note 5 of Notes to Consolidated Financial Statements.

Computer Software Costs

We capitalize costs incurred to purchase and develop internal use computer software and amortize those costs over the estimated economic life of the product. If the software is no longer useful, we immediately charge capitalized computer software costs to expense.

INVESTMENTS IN LEASE EQUITY

Prior to December 2014, TEP held a 14.1% equity interest in Springerville Unit 1 and a 7% interest in certain Springerville Common Facilities (Springerville Unit 1 Leases). The fair value of these investments is described in Note 10 of Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TEP accounted for its equity interest in the Springerville Unit 1 Lease trust using the equity method. In December 2014, following the purchase of an additional undivided interest in Springerville Unit 1, TEP transferred the balance of its investment in lease equity to Plant in Service.

ASSET RETIREMENT OBLIGATIONS

TEP has identified legal Asset Retirement Obligations (AROs) related to the retirement of certain generation assets. Additionally, TEP incurred AROs related to its photovoltaic assets as a result of entering into various ground leases. We record a liability for a legal ARO in the period in which it is incurred if it can be reasonably estimated. When a new obligation is recorded, we capitalize the cost of the liability by increasing the carrying amount of the related long-lived asset. We record the increase in the liability due to the passage of time by recognizing accretion expense in O&M expense and depreciate the capitalized cost over the useful life of the related asset or when applicable, the terms of the lease subject to ARO requirements. Beginning July 1, 2013, TEP began deferring costs associated with the majority of its legal AROs as regulatory assets because new depreciation rates approved in the 2013 TEP Rate Order include these costs.

Depreciation rates also include a component for estimated future removal costs that have not been identified as legal obligations. We recover those amounts in the rates charged to retail customers and have recorded an obligation for estimated costs of removal as regulatory liabilities.

EVALUATION OF ASSETS FOR IMPAIRMENT

We evaluate long-lived assets and investments for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If expected future cash flows (without discounting) are less than the carrying value of the asset, an impairment loss is recognized if the impairment is other-than-temporary and the loss is not recoverable through rates.

DEFERRED FINANCING COSTS

We defer the costs to issue debt and amortize such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs.

We defer and amortize the gains and losses on reacquired debt associated with regulated operations to interest expense over the remaining life of the original debt.

OPERATING REVENUES

We recognize revenues related to the sale of energy when services or commodities are delivered to customers. The billing of electricity sales to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period. At the end of the month, amounts of energy delivered since the last meter reading are estimated and the corresponding unbilled revenue is calculated using average customer Retail Rates.

For purchased power and wholesale sales contracts that are settled financially, TEP nets the sales contracts with the purchase power contracts and reflects the net amount as Electric Wholesale Sales.

TEP recognizes monthly management fees in Other Revenues as the operator of Springerville Unit 3 on behalf of Tri-State Generation and Transmission Association, Inc. (Tri-State) and Springerville Unit 4 on behalf of Salt River Project Agriculture Improvement and Power District (SRP). Additionally, Other Revenues include reimbursements from Tri-State and SRP for various operating expenses at Springerville and for the use of the Springerville Common Facilities and the Springerville Coal Handling Facilities. The offsetting expenses are recorded in the respective line items of the income statements based on the nature of services provided. As the operating agent for Tri-State and SRP, TEP may earn performance incentives based on unit availability which are recognized in Other Revenues in the period earned.

The ACC has authorized mechanisms for Lost Fixed Cost Recovery (LFCR) related to kWh sales lost due to Energy Efficiency (EE) Standards and Distributed Generation (DG). We recognize revenues in the period that verifiable energy savings occur. Revenue recognition related to the LFCR creates a regulatory asset until such time as the revenue is collected.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

We record an Allowance for Doubtful Accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales, and economic conditions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

INVENTORY

We value materials, supplies and fuel inventory at the lower of weighted average cost or market, unless evidence indicates that the weighted average cost (even if in excess of market) will be recovered in retail rates. We capitalize handling and procurement costs (such as labor, overhead costs, and transportation costs) as part of the cost of the inventory. Materials and Supplies consist of generation, transmission, and distribution construction and repair materials.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

We recover actual fuel, purchased power and transmission costs to provide electric service to retail customers through base fuel rates and a Purchased Power and Fuel Adjustment Clause (PPFAC); the ACC periodically adjusts the PPFAC rate at which TEP recovers these costs. The difference between costs recovered through rates and actual fuel, purchased power, transmission, and other approved costs to provide retail electric service is deferred. Cost over-recoveries are deferred as regulatory liabilities and cost under-recoveries are deferred as regulatory assets. See Note 2 of Notes to Consolidated Financial Statements.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS

The ACC's Renewable Energy Standard (RES) requires TEP to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements in 2025, with distributed generation accounting for 30% of the annual renewable energy requirement. TEP must file an annual RES implementation plan for review and approval by the ACC. The approved cost of carrying out this plan is recovered from retail customers through the RES surcharge. The ACC has also approved recovery of operating costs, depreciation, property taxes, and a return on investments in company-owned solar projects through the RES tariff until such costs are reflected in retail customer rates.

TEP is required to implement cost-effective Demand Side Management (DSM) programs to comply with the ACC's EE Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs. The Electric EE Standards require increasing annual targeted retail Kilowatt-hours (kWh) savings equal to 22% by 2020.

Any RES or DSM surcharge collections above or below the costs incurred to implement the plans are deferred and reflected in the financial statements as a regulatory asset or liability. TEP recognizes RES and DSM surcharge revenue in Electric Retail Sales in amounts necessary to offset recognized qualifying expenditures.

RENEWABLE ENERGY CREDITS

The ACC measures compliance with the RES requirements through Renewable Energy Credits (RECs). A REC represents one kWh generated from renewable resources. When TEP purchases renewable energy, the premium paid above the market cost of conventional power equals the REC cost recoverable through the RES surcharge. As described above, the market cost of conventional power is recoverable through the PPFAC.

When RECs are purchased, TEP records the cost of the RECs (an indefinite-lived intangible asset) as Other Assets, and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance. When RECs are reported to the ACC for compliance with RES requirements, TEP recognizes Purchased Power expense and Other Revenues in an equal amount. See Note 2 of Notes to Consolidated Financial Statements.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than for financial statement presentation purposes. Temporary differences are accounted for by recording deferred income tax assets and liabilities on our balance sheets. These assets and liabilities are recorded using enacted income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. We reduce deferred tax assets by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or the entire deferred income tax asset will not be realized.

Tax benefits are recognized when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50% likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest expense accruals relating to income tax obligations are recorded in Other Interest Expense.

Prior to 1990, TEP flowed through to ratepayers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory Assets – Noncurrent includes income taxes recoverable through future rates, which

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

reflects the future revenues due to TEP from ratepayers as these tax benefits reverse. See Note 2 of Notes to Consolidated Financial Statements.

We account for federal energy credits generated prior to 2012 using the grant accounting model. The credit is treated as deferred revenue, which is recognized over the depreciable life of the underlying asset. The deferred tax benefit of the credit is treated as a reduction to income tax expense in the year the credit arises. Federal energy credits generated since 2012 are deferred as Regulatory Liabilities – Noncurrent and amortized as a reduction in Income Tax Expense over the tax life of the underlying asset. Income Tax Expense attributable to the reduction in tax basis is accounted for in the year the federal energy credit is generated and is deferred as regulatory assets effective July 1, 2013 due to the 2013 TEP Rate Order. All other federal and state income tax credits are treated as a reduction to Income Tax Expense in the year the credit arises.

Income tax liabilities are allocated to TEP based on its taxable income as reported in the FortisUS Inc. consolidated tax return.

TAXES OTHER THAN INCOME TAXES

We act as conduits or collection agents for sales taxes, utility taxes, franchise fees, and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable to governmental agencies on the balance sheet for these taxes and assessments. These amounts are not reflected in the income statements.

DERIVATIVE INSTRUMENTS

We use various physical and financial derivative instruments, including forward contracts, financial swaps and call and put options, to meet forecasted load and reserve requirements, to reduce our exposure to energy commodity price volatility and to hedge our interest rate risk exposure. For all derivative instruments that do not meet the normal purchase or normal sale scope exception, we recognize derivative instruments as either assets or liabilities on the consolidated balance sheets and measure those instruments at fair value. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation.

Cash Flow Hedges

TEP hedges the cash flow risk associated with unfavorable changes in the variable interest rates related to the leveraged lease arrangements for the Springerville Common Lease and variable rate industrial development revenue or pollution control revenue bonds (IDBs). In addition, TEP hedges the cash flow risk associated with a long-term wholesale power supply agreement that does not qualify for regulatory recovery using a six-year power purchase swap agreement. TEP accounts for cash flow hedges as follows:

- The effective portion of the change in the fair value is recorded in AOCI and the ineffective portion, if any, is recognized in earnings; and
- When TEP determines a contract is no longer effective in offsetting the changes in cash flow of a hedged item, TEP recognizes the change in fair value in earnings. The unrealized gains and losses at that time remain in AOCI and are reclassified into earnings as the underlying hedged transaction occurs.

We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives have been and are expected to remain highly effective in offsetting changes in the cash flows of hedged items.

Energy Contracts - Regulatory Recovery

TEP is authorized to recover the costs of hedging activities entered into to mitigate energy price risk for retail customers. We record unrealized gains and losses on these energy derivatives as either a regulatory asset or regulatory liability to the extent they qualify for recovery through the PPFAC mechanism.

Energy Contracts - No Regulatory Recovery

From time to time, TEP may enter into forward contracts with long-term wholesale customers that qualify as derivatives. We record unrealized gains and losses on these energy derivatives in the income statement as they do not qualify for regulatory recovery.

Master Netting Agreements

We have elected gross presentation for our derivative contracts under master netting agreements and collateral positions. We separate all derivatives into current and long-term portions on the balance sheet.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Normal Purchases and Normal Sales

We enter into forward energy purchase and sales contracts, including options, with counterparties that have generating capacity to support our current load forecasts or counterparties that have load serving requirements. We have elected the normal purchase or normal sales exception for these contracts which are not required to be measured at fair value and are accounted for on an accrual basis.

Commodity Trading

We did not engage in trading of derivative financial instruments for the periods presented.

PENSION AND OTHER RETIREE BENEFITS

We sponsor noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. We also provide limited health care and life insurance benefits for retirees.

We recognize the underfunded status of our defined benefit pension plans as a liability on our balance sheets. The underfunded status is measured as the difference between the fair value of the pension plans' assets and the projected benefit obligation for the pension plans. We recognize a regulatory asset to the extent these future costs are probable of recovery in the rates charged to retail customers and expect to recover these costs over the estimated service lives of employees.

Additionally, we maintain a Supplemental Executive Retirement Plan (SERP) for senior management. Changes in SERP benefit obligations are recognized as a component of AOCI.

Pension and other retiree benefit expenses are determined by actuarial valuations based on assumptions that we evaluate annually. See Note 8 of Notes to Consolidated Financial Statements.

NOTE 2. REGULATORY MATTERS

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

2013 TEP RATE ORDER

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

- An annual increase in Base Rates of approximately $76 million.
- A revision in depreciation rates from an average rate of 3.32% to 3.0% for generation and distribution plant regulated by the ACC, primarily due to revised estimates of asset removal costs, which has the effect of reducing depreciation expense by approximately $11 million annually.
- A LFCR mechanism that allows TEP to recover certain non-fuel costs that would otherwise go unrecovered due to reduced retail kWh sales attributed to EE programs and DG. The LFCR rate adjusts annually and is subject to ACC review and a year-over-year cap of 1% of TEP's total retail revenues.
- An Environmental Compliance Adjustor (ECA) mechanism that allows TEP to recover the costs of complying with environmental standards required by federal or other governmental agencies between rate cases. The ECA adjusts annually to recover environmental compliance costs and is subject to ACC approval and a cap of 0.025 cents per kWh, which approximates 0.25% of TEP's total retail revenues.

COST RECOVERY MECHANISMS

Purchased Power and Fuel Adjustment Clause

The PPFAC rate is adjusted annually each April 1st (unless otherwise approved by the ACC) and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: 1) a forward component, under which TEP recovers or refunds differences between a) forecasted fuel, transmission, and purchased power costs for the upcoming calendar year and b) those embedded in the fuel rate and the current PPFAC rates; and 2) a true-up component, which reconciles

differences between actual fuel, transmission, and purchased power costs and those recovered through the combination of the fuel rate and the forward component for the preceding 12-month period.

In April 2014, the ACC approved a PPFAC rate for TEP of 0.10 cents per kWh for the period May through September 2014 and 0.50 cents per kWh for the period October 2014 through March 2015. TEP's PPFAC rate was 0.77 cents per kWh for the period of January 2013 through June 2013 and a credit of approximately 0.14 cents per kWh for the period July 2013 through April 2014.

San Juan Mine Fire Insurance Proceeds

In September 2011, a fire at the underground mine providing coal to San Juan Generating Station (San Juan) caused interruptions to mining operations and resulted in increased fuel costs. The 2013 TEP Rate Order required TEP to defer incremental fuel costs of $10 million from recovery under the PPFAC pending final resolution of an insurance claim by the San Juan Coal Company and distribution of insurance proceeds to San Juan participants. As of December 31, 2014, TEP has received insurance settlement proceeds of $8 million. The proceeds offset the deferred costs and are reflected in our cash flow statements as an other operating cash receipt. TEP expects to recover any remaining fuel costs, not reimbursed by insurance, through its PPFAC.

Environmental Compliance Adjustor

The 2013 TEP Rate Order provided for the ECA to recover costs associated with qualified investments to comply with environmental standards required by federal or other governmental agencies. The ECA rate of 0.0049 cents per kWh became effective on May 1, 2014. TEP recognized ECA revenues of less than $1 million in 2014.

Renewable Energy Standards

TEP is required to expand its use of renewable energy in order to meet the ACC’s Renewable Energy Standards (RES). TEP is authorized to recover costs associated with meeting the RES through a customer surcharge. These costs include purchases of RECs through Power Purchase Agreements (PPAs) and Performance Based Incentives (PBIs), as well as costs associated with utility-scale ownership of solar assets until the projects can be incorporated in Base Rates.

In December 2014, the ACC approved TEP's 2015 RES plan that included a spending budget of $40 million with $33 million to be recovered through the RES surcharge. TEP earned returns on solar investments of less than $1 million in 2014 and $2 million in 2013.

Energy Efficiency Standards

TEP is required to implement cost-effective DSM programs to comply with the ACC's EE Standards. The EE Standards provide for a DSM surcharge to recover, from retail customers, the costs to implement DSM programs as well as a performance incentive. For the year ended December 31, 2014, TEP recorded a DSM performance incentive of $2 million that is included in Electric Retail Revenue in the TEP income statement.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism provides recovery of certain non-fuel costs that would go unrecovered due to lost retail kWh sales as a result of implementing ACC approved EE programs and DG targets. For recovery of lost fixed costs, TEP is required to file an annual LFCR adjustment request with the ACC for costs related to the prior year, and recovery is subject to a year-over-year cap of 1% of the company's total retail revenues.

The ACC approved TEP's annual LFCR recovery request for lost fixed costs incurred in 2013 of approximately $5 million. The approved rates, of approximately 0.41% of retail revenue for EE and approximately 0.31% of retail revenue for DG, became effective August 2014.

TEP recorded, in Electric Retail Sales, LFCR revenues of $11 million for the year ended December 31, 2014 related to reductions in retail kWh sales for 2013 and 2014. We recognize LFCR revenue when verifiable regardless of when the lost retail kWh sales occur.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes regulatory assets and liabilities:

	December 31, 2014	December 31, 2013
	Millions of Dollars	
Regulatory Assets—Current		
Property Tax Deferrals [1]	$21	$20
PPFAC [2]	19	4
Derivative Instruments (Note 10)	15	1
LFCR and DSM [2]	8	3
San Juan Mine Fire Cost Deferral [2]	2	10
Other Current Regulatory Assets [3]	4	5
Total Regulatory Assets—Current	69	43
Regulatory Assets—Noncurrent		
Pension and Other Retiree Benefits (Note 8)	126	75
Income Taxes Recoverable Through Future Rates [4]	31	22
PPFAC - Final Mine Reclamation and Retiree Health Care Costs [5]	29	25
Springerville Lease Purchase Commitment Deferrals [6]	16	2
Unamortized Loss on Reacquired Debt [7]	6	7
LFCR [2]	4	—
Tucson to Nogales Transmission Line [8]	4	5
Other Regulatory Assets [3]	7	5
Total Regulatory Assets—Noncurrent	223	141
Regulatory Liabilities—Current		
RES [2]	(28)	(22)
DSM [2]	(6)	—
Fortis Merger Customer Credits [9]	(5)	—
Other Current Regulatory Liabilities	—	(2)
Total Regulatory Liabilities—Current	(39)	(24)
Regulatory Liabilities—Noncurrent		
Net Cost of Removal for Interim Retirements [10]	(265)	(254)
Deferred Investment Tax Credits [11]	(25)	(4)
Income Taxes Payable through Future Rates [4]	(20)	(5)
Fortis Merger Customer Credits [9]	(11)	—
Total Regulatory Liabilities—Noncurrent	(321)	(263)
Total Net Regulatory Assets (Liabilities)	$(68)	$(103)

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. With the exception of interest earned on under-recovered PPFAC costs, we do not earn a return on regulatory assets. Regulatory liabilities represent items that we either expect to pay to customers through billing reductions in future periods or plan to use for the purpose for which they were collected from customers.

(1) Property Taxes are recovered over approximately a six months period as costs are paid, rather than as costs are accrued.

(2) See Cost Recovery Mechanisms discussed above.

(3) Other regulatory assets include self-insured medical costs and short-term disability costs recovered on a pay-as-you-go or cash basis; San Juan Coal Contract Amendment costs (recovery through 2017); rate case costs (recovery over three years); and environmental compliance costs (recovery over one year).

(4)

Income Taxes Recoverable through Future Revenues are amortized over the life of the assets. See Note 1 of Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Final Mine Reclamation and Retiree Health Care Costs stem from TEP's jointly-owned facilities at the San Juan Generating Station, the Four Corners Generating Station, and the Navajo Generating Station. TEP is required to recognize the present value of its liability associated with final mine reclamation and retiree health care obligations over the life of the coal supply agreements. TEP recorded a regulatory asset because TEP is permitted to fully recover these costs through the PPFAC when the costs are invoiced by the miners. TEP expects to recover these costs over the remaining life of the mines, which is estimated to be between 14 and 20 years.

(6) TEP deferred the increase in lease interest expense relating to the purchase commitments for Springerville Unit 1 and the Springerville Coal Handling Facilities to a regulatory asset because TEP believes the full purchase price is recoverable in rate base. See Note 5 of Notes to Consolidated Financial Statements.

(7) In accordance with FERC guidelines, when TEP refinances its long-term debt, TEP defers and amortizes losses on reacquired debt over the life of the debt agreement.

(8) TEP will request recovery from FERC for the costs incurred to develop a high-voltage transmission line from Tucson to Nogales; the project is not going forward. See Note 6 of Notes to Consolidated Financial Statements

(9) Fortis Merger Customer Credits represent credits to be applied to customers' bills according to the Merger Agreement. These credits will be applied to customer bills each year, October through March for a period of five years. See Note 1 of Notes to Consolidated Financial Statements.

(10) Net Cost of Removal for Interim Retirements represents amounts recovered through depreciation rates associated with asset retirement costs expected to be incurred in the future.

(11) The Deferred Investment Tax Credit relates to federal energy credits generated in 2012 and is amortized over the tax life of the underlying asset.

IMPACTS OF REGULATORY ACCOUNTING

If we determine that we no longer meet the criteria for continued application of regulatory accounting, we would be required to write off our regulatory assets and liabilities related to those operations not meeting the regulatory accounting requirements. Discontinuation of regulatory accounting could have a material impact on our financial statements.

NOTE 3. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Utility Plant in Service by major class:

	December 31,	
	2014	2013
	Millions of Dollars	
Plant in Service:		
Electric Generation Plant	$2,388	$1,889
Electric Transmission Plant	898	825
Electric Distribution Plant	1,398	1,298
General Plant	338	312
Intangible Plant - Software Costs (1) (2)	149	141
Electric Plant Held for Future Use	4	3
Total Plant in Service	$5,175	$4,468
Utility Plant under Capital Leases(3)	$667	$638

(1) Unamortized computer software costs were $31 million as of December 31, 2014, and $39 million as of December 31, 2013.

(2) The amortization of computer software costs was $17 million in 2014, $14 million in 2013, and $13 million in 2012.

(3) In 2014, TEP entered into agreements to purchase certain Springerville Coal Handling Facilities leased interests. See Note 5 of Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Utility Plant under Capital Leases

All utility plant under capital leases is used in generation operations and amortized over the primary lease term. See Note 5 of Notes to Consolidated Financial Statements. At December 31, 2014, the utility plant under capital leases includes: 1) Springerville Unit 1; 2) Springerville Common Facilities; and 3) Springerville Coal Handling Facilities.

The following table shows the amount of lease expense incurred for generation-related capital leases:

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Lease Expense:			
Interest Expense – Included in:			
Capital Leases	$10	$25	$34
Operating Expenses – Fuel	1	2	3
Amortization of Capital Lease Assets – Included in:			
Operating Expenses – Fuel	6	5	4
Operating Expenses – Amortization	16	15	14
Total Lease Expense	$33	$47	$55

Utility plant depreciation rates and approximate average remaining service lives based on the most recent depreciation studies available at December 31, 2014, were as follows:

	December 31, 2014	
	Annual Depreciation Rate (3)	Average Remaining Life in Years
Major Class of Utility Plant in Service:		
Electric Generation Plant (1)	3.31%	22
Electric Transmission Plant	1.48%	32
Electric Distribution Plant (1)	2.08%	35
General Plant (1)	5.48%	11
Intangible Plant (2)	Various	Various

(1) In June 2013, the ACC issued the 2013 TEP Rate Order that approved a change in depreciation rates which reflects changes in the remaining average useful lives for our generation, distribution, and general plant assets. See Note 2 of Notes to Consolidated Financial Statements.

(2) The majority of TEP's investment in intangible plant represents computer software, which is being amortized over its expected useful life of three to five years for smaller application software. For large enterprise software, we use the remaining life depreciation method. At December 31, 2014, remaining lives ranged from one to six years.

(3) The depreciation rates represent a composite of the depreciation rates of assets within each major class of utility plant.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

JOINTLY-OWNED FACILITIES

At December 31, 2014, TEP was a participant in jointly-owned generating stations and transmission systems as follows:

	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
		Millions of Dollars			
San Juan Units 1 and 2	50.0%	$453	$8	$242	$219
Navajo Units 1, 2, and 3	7.5%	153	1	112	42
Four Corners Units 4 and 5	7.0%	104	3	77	30
Luna Energy Facility	33.3%	55	—	2	53
Gila River Unit 3	75.0%	186	—	54	132
Gila River Common Facilities	18.75%	42	—	11	31
Transmission Facilities	Various	371	21	193	199
Total		$1,364	$33	$691	$706

In December 2014, TEP completed the purchase of Gila River Unit 3. TEP jointly owns Gila River Unit 3 with UNS Electric, Inc., an affiliated subsidiary of UNS Energy (UNS Electric). See Note 7 of Notes to Consolidated Financial Statements.

TEP is responsible for its share of operating and capital costs for the above facilities. TEP accounts for its share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

Springerville Unit 1

At December 31, 2014, TEP owned 24.7% of Springerville Unit 1 and continued to lease the remaining portion of the facility. Effective January 1, 2015, following completion of the purchase of an additional 24.8% leased interest in Springerville Unit 1 and expiration of the lease, TEP has a 49.5% ownership interest in the Springerville Unit 1 generating station and will operate the facility on behalf of third parties, i.e. 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). The Third-Party Owners are responsible for their share of operating and capital costs for the facility. See Note 6 of Notes to Consolidated Financial Statements.

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and photovoltaic assets and is included in Deferred Credits and Other Liabilities on the balance sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals on the balance sheets:

	December 31, 2014	2013
	Millions of Dollars	
Beginning Balance	$22	$14
Liabilities Incurred	5	—
Accretion Expense or Regulatory Deferral	1	1
Revisions to the Present Value of Estimated Cash Flows (1)	—	7
Ending Balance	$28	$22

(1) Primarily related to changes in expected retirement dates of generating facilities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 4. RELATED PARTY TRANSACTIONS

TEP engages in various transactions with UNS Energy and its affiliated subsidiaries including Unisource Energy Services, Inc., UNS Electric, UNS Gas, Inc. (UNS Gas) and Southwest Energy Solutions, Inc. (SES) (collectively, UNS Energy affiliates). These transactions include sales and purchases of power, common cost allocations, and the provision of corporate and other labor related services. Additionally, TEP and UNS Electric jointly own a generating station unit. See Note 7 of Notes to Consolidated Financial Statements.

The following table summarizes related party transactions:

	Years Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Wholesale Sales - TEP to UNS Electric (1)	$4	$1	$2
Wholesale Sales - UNS Electric to TEP (1)	4	2	1
Control Area Services - TEP to UNS Electric (2)	3	4	3
Common Costs - TEP to UNS Energy Affiliates (3)	13	12	12
Supplemental Workforce - UNS Energy Affiliate to TEP (4)	16	16	17
Corporate Services - UNS Energy to TEP (5)	14	5	2
Corporate Services - UNS Energy Affiliates to TEP (6)	1	1	1

(1) TEP and UNS Electric sell power to each other at prevailing market prices.

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

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

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

(5) Corporate costs at UNS Energy, such as merger costs and legal 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.

(6) All Corporate Services (e.g., finance, accounting, tax, legal, and information technology) and other labor services are directly assigned to the benefiting entity at a fully burdened cost when possible.

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

	December 31, 2014	December 31, 2013
	Millions of Dollars	
Receivables from Related Parties		
UNS Electric	$4	$3
UNS Gas	1	2
UNS Energy	—	1
Total Due from Related Parties	$5	$6
Payables to Related Parties		
SES	$2	$2
UNS Electric	1	—
UNS Energy	—	7
Total Due to Related Parties	$3	$9

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 5. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

Long-term debt matures more than one year from the date of the financial statements. We summarize TEP's long-term debt in the statements of capitalization.

DEBT ISSUANCES AND REDEMPTIONS

Fixed Rate Notes

In March 2014, TEP issued $150 million of 5.0% unsecured notes due March 2044. TEP may redeem the notes prior to September 2043, with a make-whole premium plus accrued interest. After September 2043, TEP may redeem the notes at par plus accrued interest. TEP used the net proceeds to repay approximately $90 million on the outstanding borrowings under the 2010 Revolving Credit Facility with the remaining proceeds used for general corporate purposes. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding.

In September 2012, TEP issued $150 million of 3.85% unsecured notes due March 2023. TEP may call the debt prior to December 2022, with a make-whole premium plus accrued interest. After December 2022, TEP may call the debt at par plus accrued interest. The unsecured notes contain a limitation on the amount of secured debt that TEP may have outstanding. TEP used the net proceeds to repay approximately $72 million outstanding on the 2010 Revolving Credit Facility with the remaining proceeds used for general corporate purposes.

Tax-Exempt Fixed Rate Bonds

In March 2013, the Industrial Development Authority of Pima County, Arizona issued approximately $91 million aggregate principal amount of unsecured tax-exempt Industrial Development Revenue Bonds (IDRBs) for the benefit of TEP. The bonds bear interest at a fixed rate of 4.0%, mature in September 2029, and may be redeemed at par on or after March 2023. The proceeds from the sale of the bonds were deposited with a trustee to retire approximately $91 million of 6.375% unsecured tax-exempt bonds in April 2013.

Tax-Exempt Variable Rate Bonds and Interest Rate Swap

In November 2013, the Industrial Development Authority of Apache County, Arizona issued $100 million of tax-exempt, variable rate IDRBs for the benefit of TEP, due April 2032. The lender resets the interest rate monthly based on a percentage of an index rate equal to one-month LIBOR plus a bank margin rate. In 2014, the average monthly variable rate was 0.87% and ranged from 0.85% to 0.95%. In 2013, the average monthly variable rate was 0.95%. These bonds are multi-modal bonds, and the initial term is set at five years through November 2018, at which time the bonds will be subject to mandatory tender for purchase. Proceeds were deposited with a trustee to redeem $100 million variable rate bonds in December 2013.

Certain of TEP's tax-exempt, variable rate bonds are supported by Letter of Credits (LOCs) issued under the 2010 Credit Agreement and TEP Reimbursement Agreement, see below.

The following table shows interest rates (exclusive of LOC and remarketing fees) on TEP's weekly variable rate bonds, which are reset weekly by its remarketing agents:

	Years Ended December 31,		
	2014	2013	2012
Interest Rates on Bonds:			
Average Interest Rate	0.08%	0.10%	0.17%
Range of Average Weekly Rates	.05% - 0.13%	0.06% - 0.25%	0.06% - 0.26%

In September 2014, an interest rate swap TEP entered into in August 2009, expired. The interest rate swap had the economic effect of converting $50 million of variable rate bonds to a fixed rate of 2.4% from September 2009 to September 2014.

TEP MORTGAGE INDENTURE

Prior to November 2013, the 2010 Credit Agreement and the 2010 TEP Reimbursement Agreement were secured by $423 million in mortgage bonds issued under the 1992 Mortgage. As a result of a credit rating upgrade, in October 2013, TEP canceled $423 million in mortgage bonds and discharged the 1992 Mortgage, which had created a lien on and security interest in substantially all of TEP's utility plant assets. TEP's obligations under the 2010 Credit

Agreement and the 2010 TEP Reimbursement Agreement are now unsecured.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CREDIT AGREEMENTS

2014 Credit Agreement

In December 2014, TEP entered into an unsecured credit agreement (2014 Credit Agreement). The 2014 Credit Agreement provides for a $130 million term loan commitment and a $70 million revolving credit commitment. Any amounts borrowed under the revolving credit commitment can be used for general corporate purposes. Amounts borrowed under the term loan can only be used to purchase certain tax-exempt bonds in lieu of redemption. All loans made pursuant to the term loan commitment and the revolving credit commitment will be due and payable in November 2015, the termination date of the 2014 Credit Agreement.

In January 2015, amounts borrowed under the term loan commitment were used to purchase $130 million aggregate principal amount of unsecured IDRBs issued in June 2008 for the benefit of TEP. These multi-modal bonds currently bear interest at a fixed rate of 5.750% and mature in September 2029. At December 31, 2014, the bonds are classified as Long-Term Debt on TEP's balance sheet.

Loans under the 2014 Credit Agreement bear interest at a variable interest rate consisting of a spread over LIBOR or Alternate Base Rate. Alternate Base Rate is equal to the greater of (i) issuing bank's reference rate, (ii) the federal funds rate plus 1/2 of 1% or (iii) adjusted LIBOR for an interest period of one month plus 0.750%. The interest rate in effect on borrowings is LIBOR plus 0.750% for Eurodollar loans or Alternate Base Rate for Alternate Base Rate loans.

At December 31, 2014, TEP had a $70 million loan balance under the revolving credit facility and no borrowings under the term loan portion of the 2014 Credit Agreement. The revolving loan balance was included in Current Liabilities on TEP's balance sheets. At December 31, 2014, there was nothing available under the revolving credit facility and $130 million available under the term loan for the 2014 Credit Agreement. As of 01/30/15, TEP had a $130 million term loan balance outstanding under the 2014 Credit Agreement and a $70 million revolving loan balance.

2010 Credit Agreement

TEP's core credit facility, which was entered into in 2010 and amended in 2011 (2010 Credit Agreement), has an expiration date of November 2016, and will continue to provide TEP with access to $200 million of revolving credit and $82 million in LOCs supporting variable-rate tax-exempt bonds.

Interest rates and fees under the 2010 Credit Agreement are based on a pricing grid tied to TEP's credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.125% for Eurodollar loans or Alternate Base Rate plus 0.125% for Alternate Base Rate loans. The margin rate currently in effect on the $82 million LOC facility is 1.125%.

At December 31, 2014, TEP had $15 million in borrowings and $1 million outstanding in LOCs issued under the revolving credit facility for the 2010 Credit Agreement. At December 31, 2013, TEP had no borrowings and $1 million outstanding in LOCs issued under the revolving credit facility for the 2010 Credit Agreement. At December 31, 2014, there was $185 million available under the revolving credit facility for the 2010 Credit Agreement. The revolving loan balance was included in Current Liabilities on TEP's balance sheets. The outstanding LOCs are not shown as liabilities on TEP's balance sheets. As of 01/30/15, TEP had $170 million available under the 2010 Credit Agreement revolving credit facility.

2010 TEP REIMBURSEMENT AGREEMENT

A $37 million LOC was issued pursuant to the 2010 TEP Reimbursement Agreement. The LOC supports $37 million aggregate principal amount of variable rate tax-exempt bonds that were issued on behalf of TEP in December 2010. In February 2014, TEP amended the agreement to extend the LOC expiration date from 2014 to 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 1.00% per annum.

COVENANT COMPLIANCE

The 2014 Credit Agreement, 2010 Credit Agreement, 2010 TEP Reimbursement Agreement, 2013 Covenants Agreement, and certain of our long-term debt agreements contain restrictive covenants, including restrictions on additional indebtedness, liens to secure indebtedness, mergers, sales of assets, transactions with affiliates, and restricted payments.

At December 31, 2014, we were in compliance with the terms of our long-term debt, 2014 Credit Agreement, 2010 Credit Agreement, 2013 Covenants Agreement, and the 2010 TEP Reimbursement Agreement.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CAPITAL LEASE OBLIGATIONS

In January 2015, TEP reduced its capital lease obligations through the scheduled purchase payment for Springerville Unit 1 of $43 million and scheduled payments on other leases of $9 million.

Springerville Unit 1 Capital Lease Purchases

The Springerville Unit 1 Leases had an initial term to January 2015, and included a fair market value purchase option at the end of the initial lease term.

In December 2014, TEP purchased a 10.6% leased interest in Springerville Unit 1, representing 41 MW of capacity, for $20 million, the appraised value. Upon purchase, TEP reduced Capital Lease Obligations on its balance sheet for the purchase price. In January 2015, TEP purchased leased interests comprising 24.8% of Springerville Unit 1, representing 96 MW of capacity, for an aggregate purchase price of $46 million, the appraised value.

With the completion of these lease option purchases, 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 an existing facility support agreement. The Third-Party Owners are obligated to compensate TEP for their pro rata share of expenses for the unit in the amount of approximately $1.5 million per month and their share of capital expenditures, which are approximately $7 million in 2015. See Note 6 of Notes to Consolidated Financial Statements.

Springerville Coal Handling Facilities Lease Purchase Commitment

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

Upon TEP's purchase, SRP is obligated to buy a portion of the Springerville Coal Handling Facilities from TEP for approximately $24 million, and Tri-State is obligated to either 1) buy a portion of the facilities for approximately $24 million or 2) continue to make payments to TEP for the use of the facilities. No amounts have been recorded for these commitments from SRP and Tri-State at December 31, 2014.

Springerville Common Facilities Leases

The Springerville Common Facilities Leases have an initial term to December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years through 2025. Instead of extending the leases, TEP may exercise a fixed-price purchase provision. The fixed prices for the acquisition of the common facilities are $38 million in 2017 and $68 million in 2021.

TEP agreed with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that if the Springerville Coal Handling Facilities and Common Facilities Leases are not renewed, TEP will exercise the purchase options under these contracts. SRP will then be obligated to buy a portion of these facilities and Tri-State will then be obligated to either: buy a portion of these facilities; or continue making payments to TEP for the use of these facilities.

Lease Debt and Equity

Investments in Springerville Lease Debt and Equity

In January 2013, TEP received the final maturity payment of $9 million on the investment in Springerville Unit 1 lease debt. TEP also held an undivided equity ownership interest in the Springerville Unit 1 Leases totaling $36 million at December 31, 2013. At December 31, 2014, $36 million was transferred from Lease Equity Investment to Plant in Service on TEP's balance sheet.

Interest Rate Swap—Springerville Common Facilities Lease Debt

TEP’s interest rate swap hedges the floating interest rate risk associated with the Springerville Common Facilities lease debt. Interest on the lease debt is payable at six-month LIBOR plus a credit spread. The applicable spread was 1.75% at December 31, 2014 and December 31, 2013.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The swap has the effect of fixing the interest rates on the amortizing principal balances as follows:

Lease Debt Outstanding at December 31, 2014	Fixed Rate	LIBOR Spread
Notional Amount $32 million - Effective Date June 2006	5.77 %	1.75 %

TEP recorded the interest rate swap as a cash flow hedge for financial reporting purposes. See Note 10 of Notes to Consolidated Financial Statements.

DEBT MATURITIES

Long-term debt, including term loan payments, revolving credit facilities classified as long-term, and capital lease obligations mature on the following dates:

	Long-Term Debt Maturities (1)	Capital Lease Obligations	Total
	Millions of Dollars		
2015	$—	$188	$188
2016	79	16	95
2017	—	18	18
2018	100	11	111
2019	37	12	49
Total 2015 - 2019	216	245	461
Thereafter	1,159	18	1,177
Less: Imputed Interest	—	(20)	(20)
Total	$1,375	$243	$1,618

(1) $115 million of TEP's variable rate bonds are backed by LOCs issued pursuant to the 2010 Credit Agreement, which expires in November 2016, and the TEP 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bonds mature between 2022 and 2032, the above table reflects a redemption or repurchase of such bonds in 2016 and 2019 as though the LOCs terminate without replacement upon expiration of the 2010 Credit Agreement and the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate IDRBs, which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in 2018. The repayment of TEP Unsecured Notes is not reduced by the remaining $2 million original issue discount.

NOTE 6. COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL MATTERS

COMMITMENTS

At December 31, 2014, TEP had the following firm, non-cancellable, minimum purchase obligations and operating leases.

	2015	2016	2017	2018	2019	Thereafter	Total
	Millions of Dollars						
Fuel, Including Transportation	$76	$78	$76	$49	$49	$285	$613
Purchased Power	22	7	—	—	—	—	29
Transmission	6	6	6	6	4	16	44
Renewable Power Purchase Agreements	45	45	45	45	44	565	789
RES Performance-Based Incentives	8	8	8	8	8	76	116
Operating Leases:							
Land Easements and Rights-of-Way	2	1	1	1	2	77	84
Operating Leases Other	1	1	1	1	1	5	10
Total Purchase Commitments	$160	$146	$137	$110	$108	$1,024	$1,685

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fuel

TEP has long-term contracts for the purchase and delivery of coal with various expiration dates through 2031. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these contracts include a price adjustment clause that will affect the future cost. TEP expects to spend more than the minimum purchase obligations to meet its fuel requirements. TEP's fuel costs are recoverable from customers through the PPFAC.

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These contracts expire in various years between 2017 and 2040.

Purchased Power and Transmission

TEP has agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts. These contracts expire through 2017. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table are based on projected market prices as of December 31, 2014.

TEP has agreements with other utilities to provide transmission services. These contracts expire in various years between 2018 and 2028.

TEP's purchased power and transmission costs are recoverable from customers through the PPFAC mechanisms.

Renewable Power Purchase Agreements and RES Performance-Based Incentives

TEP has entered into 20 year Renewable PPAs which require TEP to purchase 100% of the output of certain renewable energy generation facilities that have achieved commercial operation. These agreements have various expiration dates through 2034. TEP has entered into additional long-term renewable PPAs to comply with RES requirements; however, TEP’s obligation to purchase power under these agreements does not begin until the facilities are operational. A portion of the cost of renewable energy is recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. See Note 2 of Notes to Consolidated Financial Statements.

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed Performance-Based Incentives (PBIs) and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. PBIs are recoverable through the RES tariff. See Note 2 of Notes to Consolidated Financial Statements.

Operating Leases

Our operating lease expense is primarily for rail cars, office facilities, land easements, and rights-of-way with varying terms, provisions, and expiration dates. TEP's operating lease expense totaled $3 million in 2014, and $2 million in each of 2013 and 2012.

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 that would extend the lease from 2019 through 2044. The participants in Navajo, including TEP, have not signed the lease amendment. Certain participants have expressed an interest in discontinuing their participation in Navajo. Negotiations 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. TEP owns 7.5% of Navajo and, in December 2014, recorded additional lease expense of approximately $2 million related to the lease extension in Deferred Credits and Other Liabilities—Other on TEP's balance sheet.

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 at 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

price specified by the Third-Party Owners. On December 3, 2014, TEP filed an answer to the FERC Action denying the allegations and requesting that the FERC dismiss the complaint. On February 19, 2015, the FERC issued an order denying the Third-Party Owners complaint.

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), alleging, among other things, that TEP has refused to comply with the Third-Party Owners' instructions to schedule their entitlement share of power and energy, that TEP failed to comply with their instructions to specify the level of fuel and fuel handling services, that TEP has failed to properly operate, maintain and make capital investments in Springerville Unit 1 during the term of the leases, that TEP has not agreed to wheel power and energy in the manner required as set forth in the FERC Action and that TEP has breached fiduciary duties claimed to be owed to the Third-Party Owners. The New York Action seeks declaratory judgments, injunctive relief, damages in an amount to be determined at trial and the Third-Party Owners’ fees and expenses.

On December 22, 2014, Wilmington Trust Company, as Owner Trustees and Lessors under the leases of the Third-Party Owners, sent a notice to TEP that alleges that TEP has defaulted under the Third-Party Owners’ leases. The notice states that the Owner Trustees, as Lessors, are exercising their rights to keep the undivided interests idle and demanding that TEP pay, on January 1, 2015, liquidated damages totaling approximately $71 million. On January 26, 2015, Wilmington Trust Company sent a second notice repeating the allegations in the December 22, 2014 notice.

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 injunctive relief sought for these claims, TEP cannot determine estimates of the range of loss at this time. TEP intends to vigorously defend itself against the claims asserted by the Third-Party Owners.

Claims Related to San Juan Generating Station

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

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

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the United States 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. The Court granted SJCC’s motion to sever its claims from the lawsuit and transfer venue to the United States District Court for the District of New Mexico, where this matter is now proceeding. 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 United States District Court for the District of New Mexico against Arizona Public Service Company (APS) and the other Four Corners Generating Station (Four Corners) participants alleging violations of the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act at Four Corners. In January 2012, EarthJustice amended their complaint alleging violations of New Source Performance Standards resulting from equipment replacements at Four Corners. Among other things, the plaintiffs seek to have the court issue an order to cease operations at Four Corners until any required PSD permits are issued and order the payment of civil penalties, including a beneficial mitigation project. In April 2012, APS filed motions to dismiss with the court for all claims asserted by EarthJustice in the amended complaint. The parties exchanged settlement proposals in January and February 2015, and have agreed to have the matter stayed until March 31, 2015 to make continued progress toward a final agreement that would resolve this matter without further litigation.

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

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

Mine Closure Reclamation at Generating Stations Not Operated by TEP

TEP pays ongoing reclamation costs related to coal mines that supply generating stations in which TEP has an ownership interest but does not operate. TEP is liable for a portion of final reclamation costs upon closure of the mines servicing Navajo, San Juan, and Four Corners. TEP’s share of reclamation costs at all three mines is expected to be $49 million upon expiration of the coal supply agreements, which expire between 2017 and 2031. The reclamation liability (present value of future liability) recorded was $22 million at December 31, 2014 and $18 million at December 31, 2013.

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

TEP’s PPFAC allows us to pass through 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-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 a greater part of the route to serve future customers and to address reliability needs. As part of the 2013 TEP Rate Order, TEP agreed to seek recovery of the project costs from the FERC before seeking rate recovery from the ACC. In 2012, TEP wrote off $5 million of the capitalized costs believed not probable of recovery and recorded a regulatory asset of $5 million for the balance deemed probable of recovery in TEP's next FERC rate case.

Performance Guarantees

The participants in each of the remote generating stations in which TEP participates, including TEP, have guaranteed certain performance obligations of the other participants. Specifically, in the event of payment default of a participant, the non-

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 December 31, 2014, there have been no such payment defaults under any of the remote generating station agreements. TEP's joint participation agreements expire in 2016 through 2046.

ENVIRONMENTAL MATTERS

Environmental Regulation

The Environmental Protection Agency (EPA) limits the amount of sulfur dioxide (SO_2), nitrogen oxide (NOx), particulate matter, mercury and other emissions released into the atmosphere by power plants. TEP capitalized $11 million in 2014, $5 million in 2013, and $2 million in 2012 in construction costs to comply with environmental requirements. TEP expects to capitalize environmental compliance costs of $28 million in 2015 and $19 million in 2016. In addition, TEP recorded O&M expenses of $5 million in 2014, $8 million in 2013, and $15 million in 2012. TEP expects environmental O&M expenses to be $4 million in each of 2015 and 2016.

TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its power plants. Complying with these changes may reduce operating efficiency. TEP expects to recover the cost of environmental compliance from its ratepayers.

Hazardous Air Pollutant Requirements

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

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

(1) Total capital expenditures and annual O&M expenses represent amounts for both Springerville Units 1 & 2, with estimated costs split equally between the two units. TEP owns 49.5% of Springerville Unit 1 with the close of the lease option purchases in December 2014 and January 2015; Third-Party Owners are responsible for 50.5% of environmental costs attributable to Springerville Unit 1. TEP continues to be responsible for 100% of environmental costs attributable to Springerville Unit 2.

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

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as Best Available Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rules call for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on 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 NOx, often resulting in a requirement to install selective catalytic reduction (SCR). Complying with the EPA’s BART rules, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of the Navajo, San Juan, and Four Corners power plants or for individual owners to continue to participate in these power plants. 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. TEP cannot predict the ultimate outcome of these matters.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Estimated NOx Emissions Control Costs:	Navajo (1)	San Juan (2)	Four Corners (3)	Sundt (4)
	Millions of Dollars			
Capital Expenditures	$28	$37	$35	$12
Annual O&M Expenses	1	1	2	5-6

(1) In August 2014, the EPA published a final 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 plant has until December 2019 to notify the EPA which option will be implemented. In addition, the installation of SCR technology could increase particulates which may require that baghouses be installed. TEP owns 7.5% of Navajo. TEP's share of the capital cost of baghouses in addition to the SCR costs reflected in the table above is approximately $28 million with O&M on the baghouses expected to be less than $1 million per year.

(2) In October 2014, the EPA published a final rule approving a 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) and Balance Draft technology on Units 1 and 4 by February 2016. Prior to the shutdown of any units at San Juan, Public Service Company of New Mexico (PNM), the operator, must first obtain New Mexico Public Regulation Commission approval. TEP owns 50% of San Juan Unit 2. At December 31, 2014, the net book value of TEP's share in San Juan Unit 2 was $110 million. TEP submitted a depreciation study in its 2013 Rate Case which identified an excess of required generation depreciation reserves. As stipulated in the 2013 Rate Order, TEP will seek the ACC's authority to apply any excess generation depreciation reserves to the unrecovered book value of any early retirement of generation assets prior to seeking additional recovery. TEP expects the excess generation depreciation reserves to fully cover the costs associated with early retirement of Unit 2.

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

(4) In June 2014, the EPA issued a final rule that would require TEP to either (i) install, by mid-2017, SNCR and dry sorbent injection 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. 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 December 31, 2014, the net book value of the Sundt coal handling facilities was $17 million. If the coal handling facilities are retired early, TEP will request ACC approval to recover all the remaining costs of the coal handling facilities.

NOTE 7. PURCHASE OF GAS-FIRED GENERATION FACILITY

On December 10, 2014, TEP and UNS Electric acquired Gila River Unit 3, a gas-fired combined cycle unit with a nominal capacity rating of 550 MW located in Gila Bend, Arizona, from a subsidiary of Entegra Power Group LLC. TEP purchased a 75% undivided interest in Gila River Unit 3 (413 MW) for $164 million, and UNS Electric purchased the remaining 25% undivided interest. Upon the closing of the transaction, the letter of credit TEP provided in June 2014 for $15 million was canceled.

TEP’s purchase of Gila River Unit 3 is intended to replace the reduction of 195 MW of output from Springerville Unit 1 and the 170 MW of capacity expected to be retired at San Juan in 2017.

The transaction has been accounted for using the acquisition method of accounting which requires that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The following table summarizes the assets acquired and liabilities assumed as of the acquisition date:

Millions of Dollars

Utility Plant - Net	$163
Materials and Supplies	2
ARO Obligation Assumed [1]	(1)
Total Purchase Price	$164

(1) The ARO obligation was recorded at net present value in Deferred Credits and Other Liabilities - Other on TEP's balance sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

We sponsor two noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. We fund the pension plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations.

We also maintain a Supplemental Executive Retirement Plan (SERP) for executive management.

OTHER RETIREE BENEFIT PLANS

TEP provides limited health care and life insurance benefits for retirees. Active TEP employees may become eligible for these benefits if they reach retirement age while working for TEP or an affiliate.

TEP funds its other retiree benefits for classified employees through a Voluntary Employee Beneficiary Association (VEBA). TEP contributed $3 million in each of 2014, 2013 and 2012 to the VEBA. Other retiree benefits for unclassified employees are self-funded.

TEP's other retiree benefit plan was amended in 2012 to increase the participant contributions for classified employees who retire after February 1, 2014. The effect on the benefit obligation was less than $1 million.

REGULATORY RECOVERY

We record changes in our non-SERP pension plans and other retiree benefit plan, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in the rates charged to retail customers. Changes in the SERP obligation, not yet reflected in net periodic benefit cost, are recorded in Other Comprehensive Income since SERP expense is not currently recoverable in rates.

The pension and other retiree benefit related amounts (excluding tax balances) included on our balance sheet are:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2014	2013	2014	2013
	Millions of Dollars			
Regulatory Pension Asset Included in Other Regulatory Assets	$117	$71	$9	$4
Accrued Benefit Liability Included in Accrued Employee Expenses	(1)	(1)	(2)	(2)
Accrued Benefit Liability Included in Pension and Other Retiree Benefits	(71)	(23)	(67)	(62)
Accumulated Other Comprehensive Loss (related to SERP)	5	2	—	—
Net Amount Recognized	$50	$49	$(60)	$(60)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

OBLIGATIONS AND FUNDED STATUS

We measured the actuarial present values of all pension benefit obligations and other retiree benefit plans at December 31, 2014 and December 31, 2013. The table below includes all of TEP's plans. All plans have projected benefit obligations in excess of fair value of plan assets for each period presented. The status of our pension benefit and other retiree benefit plans are summarized below:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2014	2013	2014	2013
	Millions of Dollars			
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	$330	$357	$74	$77
Actuarial (Gain) Loss	67	(35)	5	(5)
Interest Cost	16	14	3	3
Service Cost	10	11	4	3
Benefits Paid	(16)	(17)	(5)	(4)
Projected Benefit Obligation at End of Year	407	330	81	74
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	307	275	10	7
Actual Return on Plan Assets	35	27	1	1
Benefits Paid	(16)	(17)	(5)	(4)
Employer Contributions (1)	9	22	6	6
Fair Value of Plan Assets at End of Year	335	307	12	10
Funded Status at End of Year	$(72)	$(23)	$(69)	$(64)

(1) In 2015, TEP expects to contribute $23 million to the pension plans.

The following table provides the components of TEP's regulatory assets and accumulated other comprehensive loss that have not been recognized as components of net periodic benefit cost as of the dates presented:

	Pension Benefits		Other Retiree Benefits	
	Years Ended December 31,			
	2014	2013	2014	2013
	Millions of Dollars			
Net Loss	$118	$74	$11	$6
Prior Service Cost (Benefit)	4	—	(2)	(2)

The accumulated benefit obligation aggregated for all pension plans is $365 million at December 31, 2014 and $297 million at December 31, 2013.

Information for Pension Plans with Accumulated Benefit Obligations in excess of Pension Plan Assets:

	December 31,	
	2014	2013
	Millions of Dollars	
Accumulated Benefit Obligation at End of Year	$365	$13
Fair Value of Plan Assets at End of Year	335	—

Only the SERP, which is unfunded, had accumulated benefit obligations in excess of plan assets at December 31, 2013. Due to decreases in discount rates, and changes in mortality projections which reflect a longer life expectancy, all of our plans had accumulated benefit obligations in excess of plan assets at December 31, 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic benefit plan cost includes the following components:

	Pension Benefits			Other Retiree Benefits		
	Year Ended December 31,					
	2014	2013	2012	2014	2013	2012
	Millions of Dollars					
Service Cost	$10	$11	$9	$4	$3	$3
Interest Cost	16	14	15	3	3	3
Expected Return on Plan Assets	(21)	(19)	(17)	(1)	(1)	—
Actuarial Loss Amortization	3	8	7	—	—	—
Net Periodic Benefit Cost	$8	$14	$14	$6	$5	$6

Approximately 20% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in income.

The changes in plan assets and benefit obligations recognized as regulatory assets or in AOCI are as follows:

	Pension Benefits					
	2014		2013		2012	
	Regulatory Asset	AOCI	Regulatory Asset	AOCI	Regulatory Asset	AOCI
	Millions of Dollars					
Current Year Actuarial (Gain) Loss	$49	$3	$(42)	$(1)	$28	$1
Amortization of Actuarial Gain (Loss)	(3)	—	(8)	—	(7)	—
Total Recognized (Gain) Loss	$46	$3	$(50)	$(1)	$21	$1

	Other Retiree Benefits		
	2014	2013	2012
	Regulatory Asset	Regulatory Asset	Regulatory Asset
	Millions of Dollars		
Current Year Actuarial (Gain) Loss	$5	$(6)	$2

For all pension plans, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. We will amortize $7 million estimated net loss and less than $0.5 million prior service credit from other regulatory assets and less than $0.5 million net loss and less than $0.5 million prior service cost from AOCI into net periodic benefit cost in 2015. Less than $0.5 million estimated net loss and less than $0.5 million prior service benefit for the other retiree benefit plan will be amortized from other regulatory assets into net periodic benefit cost in 2015.

	Pension Benefits		Other Retiree Benefits	
	2014	2013	2014	2013
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31,				
Discount Rate	4.1 - 4.2%	5.0% - 5.1%	3.9%	4.7%
Rate of Compensation Increase	3.0%	3.0%	N/A	N/A

	Pension Benefits			Other Retiree Benefits		
	2014	2013	2012	2014	2013	2012
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31,						
Discount Rate	5.0% - 5.1%	4.1% - 4.1%	4.9% - 5.0%	4.7%	3.8%	4.7%

Rate of Compensation Increase	3.0%	3.0%	3.0%	N/A	N/A	N/A
Expected Return on Plan Assets	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets.

We use a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a “best-estimate” range over 20 years from the 25th percentile to the 75th percentile. The model, used as a guideline for selecting the overall rate-of-return-on-assets assumption, is based on forward looking return expectations only. The above method is used for all asset classes.

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost. The assumed health care cost trend rates follow:

	December 31, 2014	2013
Health Care Cost Trend Rate Assumed for Next Year	6.7%	6.7%
Ultimate Health Care Cost Trend Rate Assumed	4.5%	4.5%
Year that the Rate Reaches the Ultimate Trend Rate	2027	2027

Assumed health care cost trend rates significantly affect the amounts reported for health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects on the December 31, 2014, amounts:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	Millions of Dollars	
Effect on Total Service and Interest Cost Components	$1	$1
Effect on Retiree Benefit Obligation	7	6

PENSION PLAN AND OTHER RETIREE BENEFIT ASSETS

Pension Assets

We calculate the fair value of plan assets on December 31, the measurement date. Pension plan asset allocations, by asset category, on the measurement date were as follows:

	2014		2013	
Asset Category				
Equity Securities	48	%	50	%
Fixed Income Securities	43	%	40	%
Real Estate	7	%	7	%
Other	2	%	3	%
Total	100	%	100	%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables set forth the fair value measurements of pension plan assets by level within the fair value hierarchy:

	Fair Value Measurements of Pension Assets December 31, 2014			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	Millions of Dollars			
Asset Category				
Cash Equivalents	$1	$ —	$—	$1
Equity Securities:				
United States Large Cap	—	82	—	82
United States Small Cap	—	17	—	17
Non-United States	—	61	—	61
Fixed Income	—	143	—	143
Real Estate	—	8	16	24
Private Equity	—	—	7	7
Total	$1	$ 311	$23	$335

	Fair Value Measurements of Pension Assets December 31, 2013			
	Level 1	Level 2	Level 3	Total
	Millions of Dollars			
Asset Category				
Cash Equivalents	$1	$ —	$—	$1
Equity Securities:				—
United States Large Cap	—	76	—	76
United States Small Cap	—	16	—	16
Non-United States	—	62	—	62
Fixed Income	—	124	—	124
Real Estate	—	7	14	21
Private Equity	—	—	7	7
Total	$1	$ 285	$21	$307

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, United States bond funds, and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Level 3 real estate investments were valued using a real estate index value. The real estate index value was developed based on appraisals comprising 100% of real estate assets tracked by the index in 2014 and comprising 85% in 2013.

Level 3 private equity funds are classified as funds-of-funds. They are valued based on individual fund manager valuation models.

The following tables set forth a reconciliation of changes in the fair value of pension assets classified as Level 3 in the fair value hierarchy. There were no transfers in or out of Level 3.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2014		
	Private Equity	Real Estate	Total
	Millions of Dollars		
Beginning Balance at January 1, 2014	$7	$14	$21
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Ending Balance at December 31, 2014	$7	$16	$23

	Year Ended December 31, 2013		
	Private Equity	Real Estate	Total
	Millions of Dollars		
Beginning Balance at January 1, 2013	$6	$13	$19
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	1	2
Ending Balance at December 31, 2013	$7	$14	$21

Pension Plan Investments

Investment Goals

Asset allocation is the principal method for achieving each pension plan's investment objectives while maintaining appropriate levels of risk. We consider the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding are reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the pension plans. We expect to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

We recognize the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. We also recognize some risk must be assumed to achieve a pension plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: plan status, plan sponsor financial status and profitability, plan features, and workforce characteristics. We have determined that the pension plans can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. TEP tracks each pension plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the pension plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges may also be used for defensive purposes.

Relationship between Plan Assets and Benefit Obligations

The overall health of each plan will be monitored by comparing the value of plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the fair value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of plan data, but will be no less frequent than annually via actuarial valuation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Target Allocation Percentages

The current target allocation percentages for the major asset categories of the plan as of December 31, 2014 follow. Each plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	TEP Plans	VEBA Trust
Fixed Income	41%	38%
United States Large Cap	24%	39%
Non-United States Developed	15%	7%
Real Estate	8%	—%
United States Small Cap	5%	5%
Non-United States Emerging	5%	9%
Private Equity	2%	—%
Cash/Treasury Bills	—%	2%
Total	100%	100%

Pension Fund Descriptions

For each type of asset category selected by the Pension Committee, our investment consultant assembles a group of third-party fund managers and allocates a portion of the total investment to each fund manager. In the case of the private equity fund, our investment consultant directs investments to a private equity manager that invests in third-parties’ funds.

Other Retiree Benefit Assets

As of December 31, 2014, the fair value of VEBA trust assets was $12 million, of which $4 million were fixed income investments and $8 million were equities. As of December 31, 2013, the fair value of VEBA trust assets was $10 million, of which $4 million were fixed income investments and $6 million were equities. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

ESTIMATED FUTURE BENEFIT PAYMENTS

TEP expects the following benefit payments to be made by the defined benefit pension plans and other retiree benefit plan, which reflect future service, as appropriate.

	2015	2016	2017	2018	2019	2020-2024
	Millions of Dollars					
Pension Benefits	$17	$17	$19	$20	$21	$121
Other Retiree Benefits	5	5	5	5	6	33

One of TEP’s noncontributory defined benefit pension plans was amended in 2012 to allow terminated participants to elect early retirement benefits equal to the actuarial equivalent of the participant’s termination retirement benefit. The impact of the amendment on estimated future benefit payments was approximately $5 million in total, and the effect on the pension benefit obligation was less than $1 million.

DEFINED CONTRIBUTION PLAN

We offer a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account. We match part of a participant’s contributions to the plan. TEP made matching contributions to the plan of $5 million in each of 2014, 2013, and 2012.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9. SUPPLEMENTAL CASH FLOW INFORMATION

CASH PAYMENTS

	Years Ended December 31,		
	2014	2013	2012
	Thousands of Dollars		
Interest Paid, Net of Amounts Capitalized	$(82,653)	$(52,589)	(52,125)
Income Taxes Paid	—	—	(1,796)

NON-CASH TRANSACTIONS

In 2014, the following non-cash transactions occurred:

- In April 2014, TEP recorded an increase of $109 million to both Utility Plant Under Capital Leases and Current Obligations Under Capital Leases due to TEP's commitment to purchase leased interests in April 2015. See Note 5 of Notes to Consolidated Financial Statements.

In 2013, the following non-cash transactions occurred:

- TEP recorded an increase of $55 million to both Utility Plant Under Capital Leases and Capital Lease Obligations due to TEP's commitment to purchase leased interests in December 2014 and January 2015.
- In March 2013, the Industrial Development Authority of Pima County, Arizona issued approximately $91 million aggregate principal amount of unsecured tax-exempt Industrial Development Revenue Bonds (IDRBs) for the benefit of TEP. The proceeds were used to redeem debt using a trustee. Since the cash flowed through a trust account, the issuance and redemption of debt resulted in a non-cash transaction.
- In November 2013, the Industrial Development Authority of Apache County, Arizona issued $100 million of tax-exempt, variable rate IDRBs for the benefit of TEP. The proceeds were deposited with the trustee to redeem debt in December 2013. TEP had no cash receipts or payments as a result of this transaction. See Note 5 of Notes to Consolidated Financial Statements.

In 2012, the following non-cash transactions occurred:

- In June 2012, the Industrial Development Authority of Pima County, Arizona issued approximately $16 million of unsecured tax-exempt IDBs. In March 2012, the Industrial Development Authority of Apache County, Arizona issued $177 million of unsecured tax-exempt pollution control bonds. In 2012, TEP redeemed the $193 million of tax-exempt bonds and reissued debt using a trustee. Since the cash flowed through trust accounts, the redemption and reissuance of debt resulted in a non-cash transaction at TEP.

Other non-cash investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments were as follows:

	Years Ended December 31,		
	2014	2013	2012
	Thousands of Dollars		
(Decrease)/Increase to Utility Plant Accruals(1)	$5,138	$4,995	$4,813
Net Cost of Removal of Interim Retirements(2)	12,128	25,182	35,983
Capital Lease Obligations(3)	1,107	9,039	11,967
Asset Retirement Obligations(4)	4,117	8,064	789

(1) The non-cash additions to Utility Plant represent accruals for capital expenditures.

(2) The non-cash net cost of removal of interim retirements represents an accrual for future asset retirement obligations that does not impact earnings.

(3) The non-cash change in capital lease obligations represents interest accrued for accounting purposes in excess of interest payments.

(4) The non-cash additions to asset retirement obligations and related capitalized assets represent revision of estimated asset retirement cost due to changes in timing and amount of expected future asset retirement obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 10. 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.

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.

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets(5)	Net Amount
	December 31, 2014 Millions of Dollars					
Assets						
Cash Equivalents(1)	$15	$15	$—	$—	$—	$15
Restricted Cash(1)	2	2	—	—	—	2
Rabbi Trust Investments(2)	26	—	26	—	—	26
Energy Contracts - Regulatory Recovery(3)	1	—	—	1	(1)	—
Energy Contracts - No Regulatory Recovery(3)	1	—	—	1	(1)	—
Total Assets	45	17	26	2	(2)	43
Liabilities						
Energy Contracts - Regulatory Recovery(3)	(18)	—	(9)	(9)	1	(17)
Energy Contracts - No Regulatory Recovery(3)	(1)	—	—	(1)	1	—
Energy Contracts - Cash Flow Hedge(3)	(1)	—	—	(1)	—	(1)
Interest Rate Swaps(4)	(5)	—	(5)	—	—	(5)
Total Liabilities	(25)	—	(14)	(11)	2	(23)
Net Total Assets (Liabilities)	$20	$17	$12	$(9)	$—	$20

	Total	Level 1	Level 2	Level 3	Counterparty Netting of Energy Contracts Not Offset on the Balance Sheets(5)	Net Amount
	December 31, 2013 Millions of Dollars					
Assets						
Cash Equivalents(1)	$—	$—	$—	$—	$—	$—
Restricted Cash(1)	2	2	—	—	—	2
Rabbi Trust Investments(2)	22	—	22	—	—	22

Energy Contracts - Regulatory Recovery[3]	2	—	1	1	(1)	1
Total Assets	26	2	23	1	(1)	25
Liabilities						
Energy Contracts - Regulatory Recovery[3]	(2)	—	—	(2)	1	(1)
Energy Contracts - Cash Flow Hedge[3]	(1)	—	—	(1)	—	(1)
Interest Rate Swaps[4]	(7)	—	(7)	—	—	(7)
Total Liabilities	(10)	—	(7)	(3)	1	(9)
Net Total Assets (Liabilities)	$16	$2	$16	$(2)	$—	$16

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Cash Equivalents and Restricted Cash represent amounts held in money market funds and certificates of deposit valued at cost, including interest, which approximates fair market value. Cash Equivalents are included in Cash and Cash Equivalents on the balance sheets. Restricted Cash is included in Investments and Other Property – Other on the balance sheets.

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

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

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

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

DERIVATIVE INSTRUMENTS

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

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

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

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

We estimate the fair value of our gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves. In the first half of 2013, we also used this pricing model to value our power purchase options. Beginning in the third quarter of 2013, the fair value of our power purchase options is based on contractually specified option premiums instead of the Black-Scholes-Merton option pricing model because the needed inputs are no longer available. Based on the change, we transferred the purchase power options out of Level 3 and in to Level 2 at the end of third quarter of 2013. The amount transferred was less than $0.5 million. We record transfers between levels in the fair value hierarchy at the end of the reporting period. There were no other transfers between levels in the periods presented.

The valuation of our power sale option is a function of observable market variables, regional power and gas prices, as well as the ratio between the two, 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.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Cash Flow Hedges

We enter into interest rate swaps to mitigate the exposure to volatility in variable interest rates on debt. At December 31, 2014, we have one interest rate swap agreement which expires in January 2020. We also have a power purchase swap to hedge the cash flow risk associated with a long-term power supply agreement. The power purchase swap agreement expires in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statements of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $3 million.

Energy Contracts - Regulatory Recovery

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

	Year Ended December 31,		
	2014	2013	2012
	Millions of Dollars		
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets)/Liabilities	$(18)	$—	$6

Realized gains and losses on settled contracts are fully recoverable through the PPFAC.

Energy Contracts - No Regulatory Recovery

From time to time, TEP may enter into forward contracts with long-term wholesale customers that qualify as derivatives. We record unrealized gains and losses on these energy derivatives in the income statement as they do not qualify for regulatory recovery. In December 2014, TEP entered into a three-year sales option contract. The unrealized gain recorded in Electric Wholesale Sales in 2014 was less than $1 million.

Derivative Volumes

At December 31, 2014, we have energy contracts that will settle through the fourth quarter of 2017. The volumes associated with our energy contracts were as follows:

	December 31, 2014	December 31, 2013
Power Contracts GWh	2,604	779
Gas Contracts GBtu	19,932	9,615

NOTES TO 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:

	Valuation Approach	Fair Value at December 31, 2014 Assets	Liabilities	Unobservable Inputs	Range of Unobservable Input Minimum	Maximum
		Millions of Dollars				
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	30.8 %	53.29 %
Level 3 Energy Contracts		$2	$(11)			

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

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

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

	Year Ended December 31, 2014	2013
	Millions of Dollars	
Balances at Beginning of Year	$(2)	$—
Realized/Unrealized Gains/(Losses) Recorded to:		
Net Regulatory Assets/Liabilities – Derivative Instruments	(8)	(2)
Settlements	1	—
Balances at End of Year	$(9)	$(2)
	$(8)	$(1)

Total Gains/(Losses) Attributable to the Change in Unrealized Gains/(Losses)
Relating to Assets/(Liabilities) Still Held at the End of the Period

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 December 31, 2014, the value of derivative instruments in a net liability position under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $21 million, compared with $5 million at December 31, 2013. At December 31, 2014, TEP had no cash collateral posted and less than $1 million of LOCs as credit enhancements with its counterparties and held no collateral from its counterparties. The additional collateral to be posted if credit-risk contingent features were triggered would be $21 million.

FINANCIAL INSTRUMENTS NOT CARRIED AT FAIR VALUE

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

- The carrying amounts of our current maturities of long-term debt and amounts outstanding under our credit agreements approximate the fair values due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For Investment in Lease Equity, we estimated the price at which an investor would realize a target internal rate of return. Our estimates included: the mix of debt and equity an investor would use to finance the purchase; the cost of debt; the required return on equity; and income tax rates. The estimate assumed a residual value based on an appraisal of Springerville Unit 1 conducted in 2011. No impairment has been recorded as TEP expects to recover the full carrying value in retail rates. The balance was transferred to Plant in Service upon the December 2014 purchase of an additional undivided interest in Springerville Unit 1. See Note 3 of Notes to Consolidated Financial Statements.
- 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 balance sheets and the estimated fair values of our financial instruments include the following:

	Fair Value Hierarchy	December 31, 2014 Carrying Value	December 31, 2014 Fair Value	December 31, 2013 Carrying Value	December 31, 2013 Fair Value
		Millions of Dollars			
Assets:					
Investment in Lease Equity[1]	Level 3	N/A	N/A	$36	$25
Liabilities:					
Long-Term Debt	Level 2	1,372	1,457	1,223	1,214

[1] Balance was transferred to Plant in Service in December 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11. INCOME TAXES

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

	Years Ended December 31, 2014	2013	2012
	Millions of Dollars		
Federal Income Tax Expense at Statutory Rate	$56	$52	$37
State Income Tax Expense, Net of Federal Deduction	7	7	5
Federal/State Tax Credits	(5)	(2)	(1)
Allowance for Equity Funds Used During Construction	(2)	(1)	(1)
Deferred Tax Asset Valuation Allowance	—	2	—
Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset	—	(11)	—
Other	2	1	(1)
Total Federal and State Income Tax Expense	$58	$48	$39

Investment Tax Credit Basis Adjustment - Creation of Regulatory Asset

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

Income tax expense included in the income statements consists of the following:

	Years Ended December 31, 2014	2013	2012
	Millions of Dollars		
Current Tax Expense (Benefit):			
Federal	$(1)	$(8)	$(4)
State	—	(2)	(2)
Total Current Tax Expense (Benefit)	(1)	(10)	(6)
Deferred Tax Expense (Benefit):			
Federal	54	47	38
Federal Investment Tax Credits	(4)	(1)	—
State	9	12	7
Total Deferred Tax Expense (Benefit)	59	58	45
Total Federal and State Income Tax Expense	$58	$48	$39

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The significant components of deferred income tax assets and liabilities consist of the following:

	December 31, 2014	2013
	Millions of Dollars	
Gross Deferred Income Tax Assets:		
Capital Lease Obligations	$96	$127
Net Operating Loss Carryforwards	187	104
Customer Advances and Contributions in Aid of Construction	19	19
Alternative Minimum Tax Credit	24	24
Accrued Postretirement Benefits	23	23
Emission Allowance Inventory	10	10
Investment Tax Credit Carryforward	31	6
Other	54	38
Total Gross Deferred Income Tax Assets	444	351
Deferred Tax Assets Valuation Allowance	(2)	(2)
Gross Deferred Income Tax Liabilities:		
Plant – Net	(699)	(615)
Capital Lease Assets – Net	(74)	(47)
Pensions	(27)	(22)
PPFAC	(8)	(2)
Other	(24)	(20)
Total Gross Deferred Income Tax Liabilities	(832)	(706)
Net Deferred Income Tax Liabilities	$(390)	$(357)

The net deferred income tax liability on the balance sheets is as follows:

	December 31, 2014	2013
	Millions of Dollars	
Deferred Income Taxes – Current Assets	$102	$71
Deferred Income Taxes – Noncurrent Liabilities	(492)	(428)
Net Deferred Income Tax Liability	$(390)	$(357)

TEP has recorded a $2 million valuation allowance against state tax credit carryforward deferred tax assets at December 31, 2014. Management believes TEP will not produce sufficient taxable income to use all state tax credits before they expire.

As of December 31, 2014, TEP had the following carryforward amounts:

	Amount	Expiring Year
	Millions of Dollars	
Federal Net Operating Loss	$507	2031-34
State Net Operating Loss	237	2016-34
State Credits	8	2016-19
Alternative Minimum Tax Credit	24	None
Investment Tax Credits	31	2032-34

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Uncertain Tax Positions

A reconciliation of the beginning and ending balances of unrecognized tax benefits follows:

	December 31,	
	2014	2013
	Millions of Dollars	
Unrecognized Tax Benefits, Beginning of Year	$2	$23
Additions Based on Tax Positions Taken in the Current Year	2	1
Reductions of Positions from Prior Year Based on Tax Authority Ruling	—	(22)
Unrecognized Tax Benefits, End of Year	$4	$2

Unrecognized tax benefits, if recognized, would not reduce income tax expense at December 31, 2013 and December 31, 2014.

TEP recognized a $1 million reduction to interest expense in 2013 and no reduction in 2014. TEP had no interest payable balances at December 31, 2014 and December 31, 2013. We have no penalties accrued in the years presented.

In February 2013, we received a favorable ruling from the Internal Revenue Service (IRS) allowing us to deduct up-front incentive payments to customers who install renewable energy resources. These customers transfer environmental attributes or RECs associated with their renewable installations to us over the expected life of the contract for an up-front incentive payment based on the generating capacity of their installation. As a result of the IRS ruling in the first quarter of 2013, TEP reduced unrecognized tax benefits by $22 million. The changes in tax benefits primarily affected the balance sheets.

TEP has been audited by the IRS through tax year 2010. TEP is not currently under audit by any state tax agencies. The balance in unrecognized tax benefits could change in the next 12 months as a result of IRS audits, but we are unable to determine the amount of change.

Tangible Property Regulations

In September 2013, the U.S. Treasury Department released final income tax regulations on the deduction and capitalization of expenditures related to tangible property. These final regulations apply to tax years beginning on or after January 1, 2014. Several of the provisions within the regulations will require a tax accounting method change to be filed with the IRS resulting in a cumulative effect adjustment. The adoption of these regulations by TEP resulted in a $22 million increase to plant-related deferred tax liabilities and net operating loss deferred tax assets at December 31, 2014.

NOTE 12. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)
Our quarterly financial information is unaudited but, in management's opinion, includes all adjustments necessary for a fair presentation. Our utility business is seasonal in nature. Peak sales periods for TEP generally occur during the summer. Accordingly, comparisons among quarters of a year may not represent overall trends and changes in operations.

	First	Second	Third	Fourth
	Thousands of Dollars			
2014				
Operating Revenue	$255,513	$321,618	$387,411	$305,359
Operating Income	31,999	79,653	84,898	34,138
Net Income	9,172	38,725	39,644	14,797
2013				
Operating Revenue	$247,751	$304,263	$371,239	$273,437
Operating Income	22,747	53,433	123,177	31,014
Net Income	1,478	30,787	64,167	4,910

Schedule II—Valuation and Qualifying Accounts

Allowance for Doubtful Accounts (1)	Beginning Balance	Additions-Charged to Income	Deductions	Ending Balance
	Millions of Dollars			
Year Ended December 31,				
2014	$5	$2	$2	$5
2013	5	2	2	5
2012	14	3	12	5

Other Reserves (2)	Beginning Balance	Ending Balance
	Millions of Dollars	
Year Ended December 31,		
2014	$4	$5
2013	8	4
2012	4	8

(1) TEP records additions to the Allowance for Doubtful Accounts based on historical experience and any specific customer collection issues identified. Deductions principally reflect amounts charged off as uncollectible, less amounts recovered. Amounts include reserves for trade receivables, wholesales sales, and in-kind transmission imbalances.

(2) As the Other Reserves are not individually significant, additions and deductions need not be disclosed. Other reserves are made up of reserves for sales tax audits, litigation matters, and damages billable to third parties.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE
None.

ITEM 9A. CONTROLS AND PROCEDURES
TEP's Chief Executive Officer and Chief Financial Officer supervised and participated in TEP's evaluation of its disclosure controls and procedures as such term is defined under Rule 13a – 15(e) or Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of the end of the period covered by this report. Disclosure controls and procedures are controls and procedures designed to ensure that information required to be disclosed in TEP's periodic reports filed or

submitted under the Exchange Act, is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. These disclosure controls and procedures are also designed to ensure that information required to be disclosed by TEP in the reports that it files or submits under the Exchange Act is accumulated and communicated to management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based upon the evaluation performed, TEP’s Chief Executive Officer and Chief Financial Officer concluded that TEP’s disclosure controls and procedures are effective.
While TEP continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting, there has been no change in TEP’s internal control over financial reporting during 2014 that has materially affected, or is reasonably likely to materially affect, TEP’s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III
ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE
Directors
All of the members of the TEP Board of Directors are executive officers and employees of TEP, a wholly owned subsidiary of UNS Energy.
The directors of TEP are elected annually by TEP's sole shareholder, UNS Energy, acting at the direction of the Board of Directors of UNS Energy.
The names and information concerning the members of the TEP Board of Directors are set forth below:

Name	Age	Served As Director Since	Business Experience
David G. Hutchens	48	2014	Mr. Hutchens has served as Chief Executive Officer of TEP since 2014; President of TEP since 2011; Executive Vice President of TEP in 2011; Vice President of TEP from 2007-2011. Mr. Hutchens joined TEP in 1995. Mr. Hutchens' extensive experience in the electric and gas utility business and his position as President and Chief Executive Officer provide him with intimate knowledge of TEP's operations.
Kevin P. Larson	58	2014	Mr. Larson has served as Senior Vice President and Chief Financial Officer of TEP since September 2005. Mr. Larson joined TEP in 1985 and thereafter held various positions in its finance department and investment subsidiaries. He was elected Vice President in March 1997. In October 2000, he was elected Vice President and Chief Financial Officer. Mr. Larson is also a Chartered Financial Analyst. Mr. Larson's extensive experience in the electric and gas utility business and his position as Senior Vice President and Chief Financial Officer provide him with intimate knowledge of TEP's financial affairs.
Philip J. Dion	46	2014	Mr. Dion has served as Senior Vice President, Public Policy and Customer Solutions of TEP since August 2013. Mr. Dion was named Vice President, Public Policy in April 2010. Mr. Dion joined TEP in February 2008 as Vice President of Legal and Environmental Services. Mr. Dion previously held positions at the Federal Energy Regulatory Commission and the Arizona Corporation Commission. Mr. Dion’s extensive experience in utility regulatory matters and his position as Senior Vice President of Public Policy and Customer Solutions provide him with intimate knowledge of TEP's regulatory affairs.

Executive Officers
See Item 1. Business, Executive Officers of the Registrant.
Code of Ethics
See Item 1. Business, SEC Reports Available on TEP's Website.
Audit and Risk Committee of the UNS Energy Board
The Audit and Risk Committee of the Board of Directors of UNS Energy was established for the purpose of overseeing the accounting and financial reporting process and audits of the financial statements of UNS Energy and its consolidated subsidiaries, including TEP.

The Audit and Risk Committee reviews current and projected financial results of operations, selects an independent registered public accounting firm to audit UNS Energy's and TEP's financial statements annually, reviews and discusses the scope of such audit, receives and reviews the audit reports and recommendations, transmits its recommendations to the Board of Directors of The Audit and Risk Committee of UNS Energy reviews UNS Energy's and TEP's accounting and internal control procedures with the internal audit department from time to time, makes recommendations to the board of UNS Energy for any changes deemed necessary in such procedures and performs such other functions as delegated by the UNS Energy Board of Directors.

The following UNS Energy directors are members of the Audit and Risk Committee of UNS Energy's Board of Directors:

- Ramiro G. Peru, Chair
- Robert A. Elliott
- James P. Laurito
- Gregory A. Pivirotto
- Joaquin Ruiz

All Audit and Risk Committee members possess the level of financial literacy and accounting or related financial management expertise required by New York Stock Exchange (NYSE) rules. UNS Energy's Board of Directors has determined that, while each member of the Audit and Risk Committee has accounting and/or related financial management expertise, Mr. Ramiro Peru is an "audit committee financial expert" as that term is defined by applicable SEC regulations.

Compensation Committee

TEP is a wholly owned subsidiary of UNS Energy. As described in Item 11 below, the TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. The same individuals serve as executive officers of both UNS Energy and TEP and, prior to the acquisition of UNS Energy by Fortis, the UNS Board of Directors Compensation Committee made compensation decisions for such officers, including the design of the 2014 executive compensation plan described in Item 11. Following the acquisition of UNS Energy by Fortis, the UNS Energy Board of Directors dissolved its Compensation Committee and established a separately standing Human Resources and Governance Committee, which has assumed many, but not all, of the responsibilities of the former Compensation Committee, including the approval of the Compensation Discussion and Analysis (CD&A) set forth in Item 11.

The following UNS Energy directors are members of the Human Resources and Governance Committee of UNS Energy's Board of Directors:

- Louise L. Francesconi, Chair
- Lawrence J. Aldrich
- Robert A. Elliott
- Barry Perry
- John C. Walker

UNS Energy Directors

Due to the role of the Audit and Risk Committee and the Human Resources and Governance Committee of the UNS Energy Board of Directors described above, the following information is included with respect to the members of the UNS Energy Board of Directors (other than with respect to Mr. Hutchens, who is also a member of the Board of Directors of UNS Energy)

Name	Age	Served as Director Since	Business Experience
Lawrence J. Aldrich	62	2000	Chairman and Executive Director, Arizona Business Coalition on Health, since 2011; President and Chief Executive Officer of University Physicians Healthcare (UPH), a healthcare organization, from 2009 to 2010; Senior Vice President/Corporate Operations and General Counsel for UPH from 2007 to 2008; President of Aldrich Capital Company, an acquisition, management and consulting firm, since 2007; Chief Operating Officer of The Critical Path Institute, a non-profit medical research company focusing in drug development, from 2005 to 2007. Mr. Aldrich's extensive experience in the areas of public relations/advertising, finance, legal, human resources, marketing, engineering, operations, government/regulatory, information technology, insurance/health care, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Robert A. Elliott	59	2003	President and owner of Elliott Accounting, an accounting, tax, management and investment advisory services firm, since 1983; Chair of AAA of Arizona, a regional automotive and travel club, since 2014 and Director since 2007; Director and Corporate Secretary of Southern Arizona Community Bank, a banking institution, from 1998 to 2010; Television Analyst/Pre-game Show Co-host for Fox Sports Arizona from 1998 to 2009; Chairman of the Board of the Tucson Airport Authority, an airport operator/manager, from January 2006 to January 2007; President and Chairman of the Board of the National Basketball Retired Players Association from 2011-2013; Director of University of Arizona Foundation, a philanthropic organization, since 2011. Mr. Elliott's extensive experience in the areas of accounting, audit, banking and corporate tax, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Louise L. Francesconi	62	2008	President of Raytheon Missile Systems, a defense electronics corporation, from 1997 until her retirement in 2008; Director of Stryker Corporation, a medical technology company, since July 2006; Chairman of the Board of Trustees for TMC Healthcare, a hospital, since 1999; Director of Global Solar Energy, Inc., a manufacturer of solar panels and other solar-related products, from 2008 to 2011. Ms. Francesconi's extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, engineering, operations, audit, government/regulatory, information technology and insurance/healthcare, and her significant community involvement in Arizona and Tucson contribute to the

			diverse knowledge, skills and qualifications of the UNS Energy Board.
James P. Laurito	58	2014	President and CEO of Central Hudson Gas & Electric Company since November 1, 2014. Mr. Laurito joined Central Hudson as President in November 2009. Prior to that, he served as President of both New York State Electric and Gas Corporation and Rochester Gas & Electric Corporation from 2003 until 2009. Mr. Laurito's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

Barry Perry	50	2014	President and CEO of Fortis since December 31, 2014. Prior to his current position at Fortis, Mr. Perry served as Vice President, Finance and CFO of Fortis since 2004. Mr. Perry joined the Fortis organization in 2000 as VP, Finance and CFO of Newfoundland Power. Previously, he held the position of VP, Treasurer with a global forest products company and Corporate Controller with a large crude oil refinery. Mr. Perry's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Ramiro G. Peru	58	2008	Executive Vice President and Chief Financial Officer of Swift Corporation, a trucking company, from June 2007 until his retirement in December 2007; Executive Vice President and Chief Financial Officer of Phelps Dodge Corporation, a mining corporation, from 2004 to 2007; Senior Vice President and Chief Financial Officer of Phelps Dodge Corporation from 1999 to 2004; Director of Anthem, Inc. (formerly WellPoint, Inc.), a health benefits company, since 2004; Board of Directors, Fiesta Bowl, since 2012; Director of SM Energy Company since 2014. Mr. Peru’s extensive experience in the areas of accounting, corporate communications, finance, legal, human resource/benefits, audit, government/regulatory, corporate tax, information technology, insurance/health care and environmental contributes to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Gregory A. Pivirotto	62	2008	President, Chief Executive Officer and Director of University Medical Center Corporation, in Tucson, from 1994 until his retirement in 2010; Adjunct Professor at the University of Arizona College of Law since 2013; certified public accountant since 1978; Director of Arizona Hospital & Healthcare Association, a trade association providing advocacy, education and service to hospitals and other healthcare organizations, from 1997 to 2005; Director of Tucson Airport Authority, an airport operator/manager, from 2008 to January 2014; Member of the Advisory Board of Harris Bank from 2010 to 2013. Director of the Arizona Donor Network Association from 1993 to 2006 and since 2012. Mr. Pivirotto’s extensive experience in the areas of accounting, public relations/advertising, finance, legal, human resources/benefits, marketing, operations, audit, government/regulatory, banking, corporate tax, information technology and insurance/healthcare, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
Joaquin Ruiz	63	2005	Professor of Geosciences, University of Arizona, an educational institution, since 1983; Dean, College of Science, University of Arizona, since 2000; Executive Dean of the University of Arizona College of Letters, Arts and Science since 2009 and Vice President for Strategy and Innovation since 2012. Mr. Ruiz’s extensive experience in the areas of renewables and environmental, public relations/advertising, human resources/benefits,

			operations, government/regulatory, information technology, and his significant community involvement in Arizona and Tucson contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.
John C. Walker	57	2014	Executive Vice President, Western Canadian Operations of Fortis, effective August 1, 2014. His career with the Fortis Group spans more than 30 years. Mr. Walker was appointed President and CEO, FortisBC Electric in 2005 and in 2010 he also became President and CEO, FortisBC Gas and served in such position until August 2014. Prior to his leadership positions at FortisBC, he served as President and CEO, Fortis Properties from 1997 through 2005. Mr. Walker's extensive experience in the electric and gas utility business contribute to the diverse knowledge, skills and qualifications of the UNS Energy Board.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

This section describes TEP's overall executive compensation policies and practices and specifically analyzes the total compensation for the following executive officers, referred to as the Named Executives:

- Paul J. Bonavia, Board Chair and Chief Executive Officer*;
- David G. Hutchens, President and Chief Executive Officer;
- Kevin P. Larson, Senior Vice President and Chief Financial Officer;
- Philip J. Dion, Senior Vice President, Public Policy and Customer Solutions;
- Karen G. Kissinger, Vice President and Chief Compliance Officer; and
- Todd C. Hixon, Vice President and General Counsel

*Mr. Bonavia retired from his position as CEO of TEP on May 2, 2014, and his position as Board Chair of UNS Energy on September 19, 2014.

COMPENSATION PHILOSOPHY

Compensation Committee

TEP is a wholly owned subsidiary of UNS Energy. The TEP Board of Directors does not have a Compensation Committee and does not make compensation-related decisions for the executive officers of TEP. The same individuals serve as executive officers of both UNS Energy and TEP and, prior to the acquisition of UNS Energy by Fortis, the UNS Board of Directors Compensation Committee made all compensation decisions for all such officers, including the design of the 2014 executive compensation program described herein. Following the acquisition of UNS Energy by Fortis, the UNS Energy Board of Directors dissolved the Compensation Committee and established a separately standing Human Resources and Governance Committee, which has assumed many, but not all, of the responsibilities of the former Compensation Committee, including the approval of this disclosure. Because this Compensation Discussion and Analysis (CD&A) focuses on 2014 compensation, any references to a Compensation Committee in this section refer to the former UNS Energy Compensation Committee unless the UNS Energy Human Resources and Governance Committee is specifically identified.

TEP Compensation as a Component of UNS Energy Total Compensation

The Compensation Committee designs its programs to compensate UNS Energy executive officers for services to UNS Energy and all UNS Energy subsidiaries, including TEP. The amounts shown in this section represent the Named Executives' compensation allocated to TEP and its subsidiaries only, which, in 2014 amounts to 80.46% of the Named Executives total compensation for service provided to UNS Energy and its subsidiaries. The percentage allocated to TEP is obtained using the Massachusetts formula, an industry accepted method of allocating common costs to affiliated entities based on an equal weighting of payroll costs, plant/tangible assets and total revenues. References to Company refer to UNS Energy and include all UNS Energy subsidiaries. The Performance Enhancement Plan (PEP) includes target goals attributable to TEP, UNS Electric, and UNS Gas.

Objectives of the Compensation Program

The Compensation Committee has established a balanced total compensation program and ensures that a significant part of executive officer compensation is performance-based. Corporate goals are designed to focus executive officers and all non-union employees on successful execution of the Company's strategy and annual operating plan.

The Company's executive officer compensation policies and decisions have the following objectives:

1. Attracting, motivating and retaining highly-skilled executives;
2. Linking the payment of compensation to the achievement of critical short- and long-term financial and strategic objectives; providing safe, reliable and economically available electric and gas service; and aligning performance objectives of management with those of its other employees by using similar performance measures for both groups;

3. Balancing risk and reward to align the interests of management with those of the Company’s stakeholders and encouraging management to think and act like owners, taking into account the interests of the public that the Company serves;
4. Maximizing the financial efficiency of the compensation program to avoid unnecessary tax, accounting and cash flow costs; and
5. Encouraging management to achieve outstanding results through appropriate means by delivering compensation in a manner consistent with established and emerging corporate governance “best practices.”

Summary of 2014 Executive Officer Compensation Program

Compensation Component	Key Features	Purpose
Base Salary	Increases considered on an annual basis to remain near the median of the Company's peer group (as described in Element of Compensation - Base Salary, below) Intended to constitute a sufficient component of total compensation to discourage inappropriate risk-taking	Provide a fixed amount of cash compensation to the Company's Named Executives
Short-term Incentive Compensation (Performance Enhancement Program or PEP)	Incentive plans are structured identically for executive and non-executive employees and across business units/functions, uniting all non-union employees in the achievement of common goals All incentive plans are capped at 150% of target, protecting against the possibility that executives take short-term actions not supportive of long-term objectives to maximize bonuses Must achieve at least the threshold level of net income to receive payment above 50% of target for other performance measures; this cap limits non-financial goal payout if the financial goals are not met	Motivate and reward achieving or exceeding the Company's short-term performance goals, reinforcing pay-for-performance Focus entire Company on key customer, operational and financial objectives
Long-Term Incentive Compensation (LTI or equity-based compensation)	LTI compensation is delivered in a combination of performance shares and restricted stock units Ultimate value earned from the LTI program is based on both absolute and relative shareholder value and longer-term operating performance Performance shares represent 67% of the target award with 50% of the shares earned based on achievement of cumulative net income goals and 50% of the shares earned based on achievement of relative TSR over a three-year period RSUs represent 33% of the target awards, and cliff vest on the 3rd anniversary of grant	Opportunities for ownership and financial reward in support of the Company’s longer-term financial goals and stock price growth; also supports retention objective Provide a link between compensation and long-term shareholder interests as reflected in changes in stock price

The Compensation Committee considers decisions regarding each component of pay in the context of each executive officer’s total compensation. For example, if the Compensation Committee increases an executive officer’s base salary, it also considers the resultant impact on short- and long-term performance-based incentive compensation and compares total compensation levels to competitive practice, see Compensation Analysis, below. The Compensation Committee does not directly consider the value of previous equity awards in setting current year total compensation opportunities, but does review the value of outstanding equity awards to assess the degree to which such awards support the Company's performance motivation, retention, and shareholder alignment objectives.

Each of these components is described in more detail below and in the narrative and footnotes to the supporting tables. The following sections highlight how the above objectives are reflected in the Company's compensation program.

Attracting, Retaining and Motivating Executives

To attract, retain and motivate highly-skilled employees, the Company provides the Named Executives with compensation packages that are competitive with those offered by other electric and gas utility companies of comparable size and complexity and/or electric and gas utility companies thought to be competitors for executives. The Compensation Committee generally targets total direct compensation for the Named Executives to be, on average, at the median of selected comparable companies identified below under the Compensation Analysis section. Under this approach, newly promoted executives and those new to their role may be placed below the median to reflect their limited experience and evolving skill set. Similarly, executives with longer tenure and therefore an above-market skill set, or those executives who are sustained high performers over time and are most critical to the Company's long-term success, may be placed above the median. The Company believes that this strategy enables it to successfully hire, motivate and retain talented executives while ensuring a reasonable overall compensation cost structure relative to its peers.

In addition to providing competitive direct compensation opportunities, the Company also provides certain indirect compensation and benefits programs that are intended to assist in attracting and retaining high quality executives. These programs include pension and retirement programs and are described in more detail below and in the narratives that accompany the tables that follow this section.

Linking Compensation to Performance

The Company's compensation program seeks to link the actual compensation earned by the Named Executives to their performance and that of the Company. Prior to the merger, UNS achieved this goal primarily through two elements of executive compensation: (i) short-term cash awards and (ii) equity-based compensation. After the merger, UNS did not use equity-based compensation in 2014. To ensure that the executive officers are held accountable for achieving the Company's financial, operational and strategic objectives and for creating shareholder value, the Company believes that the percentage of pay at risk should increase with the level of responsibility within the Company. The target amounts of performance-based pay programs comprise approximately 45% to 70% of the total direct compensation opportunity for the Named Executives. Of the performance-based compensation, approximately 30-50% is short-term and 50-70% is long-term. Placing a greater emphasis on long-term performance-based compensation encourages executive officers to focus on the long-term impact of their actions. Non-variable compensation, such as benefits and perquisites, is de-emphasized in the total compensation program to reinforce the linkage between compensation and performance.

Balancing Risk and Reward to Align the Interests of the Company's Named Executives with Stakeholders

The Company's compensation program seeks to align the interests of the Named Executives with those of the Company's key stakeholders, including shareholders, customers, the community and employees. The Company uses the short-term incentive compensation component to focus the Named Executives on the importance of providing safe and reliable customer service, creating a safe work environment for employees and improving financial performance by linking their short-term cash incentive compensation to achievement of these objectives. Prior to the Merger, the Company primarily relied on the equity compensation element of its compensation package to align the interests of the Named Executives with those of the former UNS Energy shareholders. The Company's compensation strategy was intended to mitigate risk by emphasizing long-term compensation and financial performance measures correlated with shareholder value. UNS Energy believed that equity-based compensation, together with the three-year vesting of stock-based awards and the stock ownership guidelines, result in compensation programs that did not encourage excessive risk-taking by management relating to the Company's business and operations, and increase executive officer accountability in the performance of the Company. In addition, the Compensation Committee has the ability to reduce short-term incentive compensation award payouts, in its sole discretion, based upon factors other than Company performance measures. In considering the design alternatives, the Compensation Committee continually evaluates the potential for unintended consequences of its compensation program.

Maximizing the Financial Efficiency of the Program

In structuring the total compensation package for the Named Executives, the Compensation Committee evaluates the accounting cost, cash flow implications and tax deductibility of compensation to mitigate financial inefficiencies to the greatest extent possible. For instance, as part of this process, the Compensation Committee evaluates whether compensation costs are fixed or variable and places a heavier weighting on variable pay elements to calibrate expense with the achievement of operating performance objectives.

Adhering to Corporate Governance “Best Practices”

The Compensation Committee continually seeks to evaluate the executive officer compensation program in light of corporate governance “best practices.” For example, the short-term and long-term incentive compensation programs include a clawback provision, and the Change in Control Agreements does not contain an excise tax gross-up provision, all of which are discussed in more detail below.

The Compensation Committee also reviews tally sheets and wealth accumulation analysis, which are designed to assist the Compensation Committee in evaluating the reasonableness of the compensation provided to Named Executives. Based on this review, the Compensation Committee concluded that the current program design supports the Company’s objectives and that no changes were warranted to the program for 2014 compensation.

Compensation Analysis

To provide a foundation for the executive officer compensation program, the Company periodically benchmarks its Named Executives’ compensation levels and practices against a peer group of companies intended to represent the Company's competitors for business and talent. The peer group, which is reviewed periodically and approved by the Compensation Committee, includes the 12 utility companies named below that are comparable to UNS Energy in size, as measured by annual revenues and market capitalization (the Peer Group). As of November 2013, the date when the most recent benchmarking analysis was performed, UNS Energy’s revenues and number of employees approximate the median of the Peer Group; total assets and market capitalization are between the 25th percentile and the median; net income is below the 25th percentile.

Frederic W. Cook & Co., Inc., the independent consultant retained by the Compensation Committee, supplements the benchmark information annually with information relating to general market trends, changes in regulatory requirements related to executive officer compensation and emerging “best practices” in corporate governance.

2014 Peer Group

ALLETE, Inc.	NorthWestern Corp.
Avista Corp.	NV Energy, Inc.
Cleco Corp.	PNM Resources Inc.
El Paso Electric Co.	Portland General Electric Co.
Great Plains Energy, Inc.	UIL Holdings Corp.
IDACORP Inc.	Westar Energy Inc.

ELEMENTS OF COMPENSATION

Base Salary

The Company uses base salary to provide each Named Executive a set amount of money during the year with the expectation that he or she will perform his or her responsibilities to the best of his or her ability and in the best interests of the Company. The Company believes that competitive base salaries are necessary to attract and retain executive talent critical to achieving its business goals. In general, Named Executives’ base salaries are targeted to the median of the Peer Group described above. However, individual salaries can and do vary from the Peer Group median data based on such factors as (i) the competitive environment for Named Executives, and (ii) incumbent responsibilities, experience, skills and performance relative to similarly situated executive officers within the Company. Named Executives' salaries range from below the 25th percentile to the median of the Peer Group.

Increases to Named Executives’ base salaries are considered annually by the Compensation Committee. In approving base pay increases for Named Executives other than the CEO, the Compensation Committee also considers recommendations made by the CEO.

In February 2014, the Compensation Committee approved 3% base salary increases for the Named Executives, which were consistent with salary increases as a percent of salary for other non-union Company employees. Separately, the Compensation Committee approved a promotion for David Hutchens to President & CEO effective May 2, 2014, at which time his base salary was increased to $540,000 to address the added responsibility of CEO. Base salary as a percentage of total compensation for the Named Executives ranges from approximately 30-55%. Additional information is provided in the Summary Compensation Table below.

Short-Term Incentive Compensation (Cash Awards)

The Company's short-term incentive compensation consists of cash awards under the Performance Enhancement Plan ("PEP"), which links a significant portion of the Named Executives' annual compensation to the Company's annual financial and operational performance.

Each year, before the end of the first quarter, the Compensation Committee establishes performance objectives that must be met in whole or in part before the Company pays PEP awards. The key performance objectives are tailored to drive behavior that supports the Company's strategy of delivering safe, reliable service and value to customers and a fair return to shareholders over time. The Compensation Committee generally attempts to align the target opportunity for each Named Executive, stated as a percentage of base salary, with the median rate for equivalent positions at the Peer Group companies. In 2014, the target incentive opportunity for the Named Executives ranged from 40% to 80% of base salary, depending upon the Named Executive's responsibilities (i.e., the greater the responsibility, the more pay at risk). The Company's Named Executives' target incentive opportunities as a percent of base salary are near the Peer Group median. As described more fully below, the actual amounts paid depend on the achievement of specified performance objectives and could range from 50% of the target award upon achievement of threshold performance to 150.0% of the target award upon achievement of exceptional performance.

Financial and Operating Performance Objectives-2014

The PEP performance targets and weighting are based on factors that are essential for the long-term success of the Company and are identical to the performance objectives used in its performance plan for other non-union employees. In 2014, the objectives were (i) net income; (ii) O&M cost containment; and (iii) excellent operations and safe work environment, which include both quantitative and qualitative measures. The Compensation Committee selected the goals and individual weightings for the 2014 PEP to ensure an appropriate focus on profitable growth and expense control, as well as operational and customer service excellence, process improvements, and establishing new rates. This balanced scorecard approach encourages all employees to work toward common goals that are in the interests of UNS Energy's various stakeholders.

The financial and other metrics for the Company's 2014 Short-Term Incentive Compensation program were:

- Financial – 50%
- Net Income – 40%
- O&M Cost Containment – 10%
- Excellent Operations and Safe Work Environment – 50%

In developing the PEP performance targets, Company management compiles relevant data such as Company historic performance and industry benchmarks and makes recommendations to the Compensation Committee for a particular year, but the Compensation Committee ultimately determines the performance objectives that are adopted.

The 2014 financial performance objectives were:

Performance Objectives	Threshold	Target	Exceptional
	Millions of Dollars		
Net Income	$133.5	$141.9	$150.3
O&M Costs	279.0	274.0	269.0

The 2014 performance objectives were:

	Threshold	Target	Exceptional
Excellent Operations			
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	91.0%	91.1% - 92.0%	92.1% +
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	81-95	60-80	< 60
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Powers	635	656	≥665
Generation Mix - Diversify Fuel Mix	SGS Unit 1	SGS Unit 1 & Combined Cycle Asset	SGS Unit 1, Combined Cycle Asset and a 3-year firm wholesale sale with a third party or complete long-term firm wholesale sale to a third party, revised hedging plan
Safe Work Environment			
OSHA Rate (Employee Safety Measure)	1.90 and Safety Process Analysis (SPA) complete	1.50 and SPA and 80% Process Improvement Goals	< 1.1 and SPA and 90% Process Improvement Goals

2014 PEP Results

Effect of the Merger on 2014 PEP:

The Merger agreement called for PEP to be paid 30 days from the date of the closing of the Merger, in a manner consistent with past practices. Since the PEP program is based on annual goals, we used a combination of actual results as of the merger date and forecasted performance for the rest of the year where needed in an effort to establish a fair and consistent manner of reviewing goal attainment.

Summary:

Overall, the 2014 combined actual and forecasted results produced a total weighted performance for all goals of 108.7% of target performance, as summarized in Table A below. The Compensation Committee approved an overall PEP payout of 108.7% of target awards for all participants. Individual performance was not factored into any individual payouts in 2014 given the timeline requiring distribution of PEP awards within 30 days of the Merger.

The actual final 2014 year-end PEP results would have calculated to a total payout of 118.7% under the program. Three goals contributed to the difference between the results forecasted in August 2014 for PEP payments made in September 2014 and the actual final year-end results: 1) UNS Energy's 2014 Net Income was significantly higher than the August forecast; 2) the reliability measure SAIDI performed at a year-end "Exceptional" level rather than the forecasted "Target" performance; and 3) the safety incident rate was higher than forecasted at year-end resulting in a final outcome of "Threshold" rather than "Target" performance.

Table A: Summary of 2014 PEP Results

Goal	Weighting of Goal (A)	Percentage of Target Performance Achieved (B) [1]	Payout Percentage (A x B)
Net Income	40%	100%	40.0%
Safe Work Environment	5%	100%	5.0%
O&M Cost Containment	10.0%	112%	11.2%
Excellent Operations	45.0%	Various	52.50%
	100%		108.7%

(1) Additional details provided below.

Net Income Goal:

In 2014, the Company projected $141.9 million of net income, which was target performance. The calculation, per the Merger Agreement, was based on net income excluding any merger-related costs. Table B, below, reflects the net income goal, which ranged from $133.5 million (threshold) to $150.3 million (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the actual net income achieved for 2014. Net income must have been more than $133.5 million to produce a payout. The anticipated achievement of $141.9 million in net income resulted in a payout level of 100% of the target amount for that performance objective. Achievement was calculated on actual results from January to June 2014, plus forecasted results from July to December 2014.

Table B: Net Income

	Final Result: $141.9										
	Range (Millions of Dollars)										
	$134	$135	$137	$139	$140	$142	$144	$145	$147	$149	$150
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	á					á					á
	Threshold					Target				Exceptional	

O&M Cost Containment Goal:

The Company projected an O&M spending level for 2014 of $272.8 million. For this goal, lower spending represents better performance. O&M spending, for purposes of a PEP calculation, is defined as the sum of O&M expenses for TEP and UES operations, excluding (1) any reimbursable items for O&M costs incurred by TEP for operating Units 3 and 4 at the Springerville Generating Station; (2) reimbursable O&M expenses for renewable and demand side management programs; (3) any PEP accrued expense; and (4) any merger-related costs. TEP operates Unit 3 for Tri-State, which leases the unit from financial owners, and Unit 4, which is owned by Salt River Project Agricultural Improvement and Power District. Achievement was calculated on actual results from January to June 2014, plus forecasted results from July to December 2014. Table C, below, reflects the O&M cost containment goal, which ranged from $279 million (threshold) to $269 million (exceptional), and the corresponding payout levels, which ranged from 50% to 150% of the target award, as well as the anticipated O&M spending level achieved for 2014. The achievement of O&M spending of $272.8 million was less than the threshold amount of $279 million, which resulted in a payout level of 112.0%.

Table C: O & M Cost Containment

	Final Result: $272.8										
	Range (Millions of Dollars)										
	$279	$278	$277	$276	$275	$274	$273	$272	$271	$270	$269
Payout % of Target	50%	60%	70%	80%	90%	100%	110%	120%	130%	140%	150%
	á					á					á
	Threshold					Target				Exceptional	

Excellent Operations Goals:

- Equivalent Availability Factor (“EAF”): The reliability of the Company's plant performance during the peak summer demand season is critical to its customers and due to approved rate design, to financial performance; therefore, a Summer EAF goal is used in measuring the reliability of the Company's coal generation fleet.
- System Average Interruption Duration Index (“SAIDI”): This reliability measure in the Company's Transmission and Distribution business area is a good outage duration performance measure, as it tracks the length or duration of outages across all customers, giving the Company a focus on reducing the outage time a customer experiences. UNS Energy generally compares well to industry ranges given by the EEI. Achievement was calculated on actual results from January to July 2014, plus forecasted results based on five years of historical trends from August to December 2014.
- Customer Satisfaction: In 2014, the Company introduced a new Customer Satisfaction goal, measured by our JD Power performance. A concentration on improving our interactions with our customers was critical to the outcome of this goal. Focus areas included call center response time, customer communication improvements, and a new outage

map. Achievement of this goal was based on the first two 2014 quarter results, which was all that was available at the time of calculation.

- Generation Mix: The Company has had a strong focus on executing the strategy around our generation fleet as we divest of coal and optimize our generation resources. The goal concentrated on wholesale sales and the successful acquisition of a new power plant. Achievement of this goal was based on a status update of three separate transactions all contributing to the success of this goal.

Safe Work Environment Goal:

- Safety: The Company's safety measure tracks the OSHA Recordable Incident Rate, which is a good indicator of a company's safety efforts. Continued focus on safety initiative components (leadership, employee involvement, and regulatory compliance) is a priority for the Company. Historically the Company has continued to improve its safety record. Achievement was calculated on actual results from January to July 2014, plus forecasted results based on five years of historical trends from August to December 2014.

Table D, below, reflects the final achievement at the various levels of performance for the Excellent Operations and Safe Work Environment goals. According to the guidelines set by the Compensation Committee, the achievement of these goals yielded a result of 57.5% for this combination of performance objectives.

Table D: Excellent Operations/Safe Work Environment Goals

	Weight	Actual Result	Final Value	Totals
Excellent Operations (45.0% Weighting)				
Equivalent Availability Factor ("EAF") Generation Reliability – Summer	7.50%	Below Threshold	—%	
System Average Interruption Duration Index ("SAIDI") Transmission/Distribution Reliability	7.50%	Target	7.50%	
Customer Satisfaction - Improve Residential Customer Satisfaction Score Measured by JD Powers	15.00%	Exceptional	22.50%	
Generation Mix - Diversify Fuel Mix	15.00%	Exceptional	22.50%	
Subtotal: Excellent Operations				52.50%
Safe Work Environment (5.0% Weighting)				
OSHA Rate (Employee Safety Measure)	5.00%	Target	5.00%	
Subtotal: Safe Work Environment				5.00%
Total Percentage for Excellent Operations and Safe Work Environment				57.50%

The Company's internal audit department verified that the reported results for the 2014 PEP goals were accurate and reported its findings to the Compensation Committee at the time of the Merger.

The amounts of the 2014 PEP awards paid to each of the Named Executives are listed in the Summary Compensation Table below.

Long-Term Incentive Compensation (Equity Awards)

Prior to the Merger, UNS Energy believed that equity awards, in tandem with the Company's executive officer stock ownership guidelines discussed below, encouraged ownership of UNS Energy stock by executive officers and held executive officers accountable for the long-term impact of their actions, which in turn aligned the interest of those executive officers with the interest of UNS Energy's shareholders. In addition, the vesting provisions applicable to the awards encouraged a focus on long-term operating performance, linking compensation expense to the achievement of multi-year financial results and helping to retain executive officers.

The long-term incentive ("LTI") opportunity for each Named Executive is based on a percentage of salary. The 2014 LTI multiples are 125% for Mr. Hutchens, 100% for Mr. Larson, 125% for Mr. Dion, 40% for Ms. Kissinger, and 40% for Mr. Hixon. Mr. Dion's 2014 LTI opportunity reflects his contribution to TEP's 2013 rate case and will return to its regular percentage in 2015. The 2014 LTI multiple was 150% of base salary for Mr. Bonavia, who retired from his position as CEO of TEP on May 2, 2014. The values of the Named Executives' long-term incentives, as a dollar value, are generally in the 25th percentile to median range of the Peer Group. Under the design of the compensation plan for 2014, two-thirds of the award opportunity was to be granted as performance shares and one-third was granted as restricted stock units that vest 100% on the third anniversary of grant to support retention objectives as well as succession planning initiatives. Pursuant to the terms of the Merger agreement, the outstanding 2012, 2013, and 2014

LTI awards were canceled in exchange for cash payments to each of the Named Executives at the time of the merger.

2014 Performance Shares

If the Merger had not occurred, performance share awards granted in 2014 were to be distributed, along with dividend equivalents (to the extent that the performance shares become earned and vested), at the end of the three-year performance period ending in 2016, based on the following equally-weighted performance targets:

TSR Performance Criteria

TSR Percentile Rank	Payout as a Percent of Target Award
75th percentile and above	75.0%
62.5th percentile	62.5%
50th percentile	50.0%
42.5th percentile	37.5%
35th percentile	25.0%
Below 35th percentile	0.0%

Intermediate payouts determined by interpolation.

Cumulative Net Income Performance Criteria

Degree of Performance Attainment	Three-Year Cumulative Net Income Millions of Dollars	Payout as a Percent of Target Award Earned	
Outstanding	$531	75.0	%
Target	462	50.0	%
Threshold	393	17.5	%
Less than Threshold	< 393	0.0	%

Intermediate payouts determined by interpolation.

Equity Grant Timing and Practice

Generally, during the first quarter following the close of a fiscal year, prior to the Merger, the Compensation Committee approved and granted the long-term incentive awards for that year, including the type of equity to be granted, as well as the size of the awards for Named Executives. In determining the type and aggregate size of awards to be provided, as well as the performance metrics that would apply, the Compensation Committee considered the strategic goals of the Company, trends in corporate governance, accounting impact, tax deductibility, cash flow considerations, the impact on earnings per share and the number of shares that would be required to be allocated for the award and the resulting impact to shareholders. The timing of awards was not coordinated with the release of material non-public information.

CLAWBACK PROVISION FOR VARIABLE COMPENSATION

Consistent with current “best practices,” all short- and long-term incentive compensation awards approved after 2009 are subject to a clawback provision. The clawback provision may apply to the income derived from the financial component of the PEP and the performance shares in the event of a restatement of financial results that, in the view of the Compensation Committee, results from intentional misconduct or intentional error. The Compensation Committee has discretion to determine to whom the clawback will apply and the amount subject to clawback, if such repayment is determined to be necessary.

ELEMENTS OF POST EMPLOYMENT COMPENSATION

Termination and Change in Control

The Compensation Committee determined that it is in the Company’s and shareholders’ best interest to enter into change in control agreements with its executive officers in order to attract highly qualified executives and to retain those executives through any future challenges that might arise. All of these agreements were designed to be consistent with contemporary “best practices,” such as double trigger severance payments and equity vesting and no excise tax gross-ups. These various agreements and the effects of the Merger are discussed in detail in Potential Payments Upon Termination or Change in Control, below.

Generally speaking, the Company does not enter into or extend employment agreements with current officers and instead only uses employment agreements when needed in recruiting a new officer. The Company currently has no employment agreements in place.

UNS Energy also maintains a severance pay plan for all of the Company's non-union employees, including its Named Executives, which continues the Company's historical practice of providing severance pay in certain termination situations without a change in control and provides consistency in that practice.

Retirement and Other Benefits

The Company offers retirement and other core benefits to its employees, including the Named Executives, in order to provide them with a reasonable level of financial support in the event of illness or injury and to enhance productivity and job satisfaction. The benefits are the same for all employees and Named Executives and include medical and dental coverage, disability insurance and life insurance. In addition, the Tucson Electric Power Company 401(k) Plan (the "401(k) Plan") and the Tucson Electric Power Company Salaried Employees Retirement Plan (the "Retirement Plan") provide a reasonable level of retirement income reflecting employees' careers with the Company. All employees, including Named Executives, participate in these plans; the cost of these benefits (other than the Retirement Plan) is partially borne by the employee, including each Named Executive. In addition, the Company provides all of its officers with an optional executive physical annually.

To the extent that any executive officer's retirement benefit exceeds Internal Revenue Code (Code) limits for amounts that can be paid through a qualified plan, the Company also offers non-qualified retirement plans, including the Tucson Electric Power Company Excess Benefit Plan (Excess Benefit Plan) and the Management and Directors Deferred Compensation Plan (DCP). These plans provide only the difference between the calculated benefits and Code limits. These benefits are not tied to any formal individual or Company performance criteria but are intended to enhance the attraction and retention value of the executive officer compensation program and are consistent with similar competitive compensation benefits made available to executives in the industry. UNS Energy believes the DCP and the Excess Benefit Plan assist with the Company's attraction and retention objectives. The DCP provides an industry-competitive and tax-efficient benefit to the executive officers. The DCP is not funded by the Company, and participants have an unsecured contractual commitment by the Company to pay amounts owed under the DCP. The Excess Benefit Plan provides the retirement benefits to executive officers that would have been provided under the Retirement Plan if the Code limitations did not apply. For more information on retirement and certain related benefits, see the discussion in Pension Benefits and Non-Qualified Deferred Compensation, below.

ROLE OF EXECUTIVES IN ESTABLISHING COMPENSATION

Certain executive officers, including the CEO, the CFO, the General Counsel and the Vice President of Human Resources and Information Technology, routinely attend regular sessions of Compensation Committee meetings; however, they are excused for executive sessions when their compensation is discussed and/or determined. The CEO makes recommendations to the Compensation Committee with respect to changes in compensation for senior executive officer positions (other than the CEO) and payouts under the annual incentive plan. The CEO also makes suggestions to the Compensation Committee regarding the design of incentive plans and other programs in which senior management participates.

The CFO provides information regarding short-term and long-term compensation targets, as well as updates on the progress of short- and long-term objectives. Additional Company personnel with expertise in and responsibility for compensation and benefits provide information regarding executive officer and director compensation, including cash compensation, equity awards, pensions, deferred compensation and other related information.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

The Human Resources and Governance Committee has reviewed and discussed with management the Compensation Discussion and Analysis section required by Item 402(b) of SEC Regulation S-K and contained in this annual report. Based on such review and discussions, the Human Resources and Governance Committee recommended to the Board of Directors of TEP that the Compensation Discussion and Analysis section be included in TEP's annual report on Form 10-K for the year ending December 31, 2014.

Respectfully submitted,

THE HUMAN RESOURCES AND GOVERNANCE COMMITTEE OF UNS ENERGY CORPORATION

Louise L. Francesconi, Chair
Lawrence J. Aldrich
Robert A. Elliott
Barry Perry
John C. Walker

SUMMARY COMPENSATION TABLE – 2014[1)]

The following table sets forth summary compensation information for the years ended December 31, 2012; December 31, 2013; and December 31, 2014 for the Company's Named Executives. Note that the column titled All Other Compensation includes for 2014 amounts received by the Named Executives for cancellation of all outstanding equity awards, including awards that were previously disclosed in the Summary Compensation Table in prior years, to the extent those awards represent compensation for services to TEP and its subsidiaries.

Name and Principal Position	Year	Salary	Stock Awards [(4)]	Non-Equity Incentive Plan Compensation [(5)]	Change in Pension Value and Non-Qualified Deferred Compensation Earnings [(6)]	All Other Compensation [(2)]	Total
Paul J. Bonavia	2014	$446,870	$790,257	$465,729	$261,168	$5,474,229	$7,438,253
Former Board	2013	512,726	904,888	417,196	165,574	13,948	2,014,331
Chair and Chief Executive Officer [(7)]	2012	498,557	933,643	377,372	228,697	13,408	2,051,677
David G.	2014	397,962	417,359	377,827	555,358	2,529,306	4,277,812
Hutchens	2013	306,482	432,998	198,513	105,379	14,209	1,057,580
President and Chief Executive Officer [(3)]	2012	286,116	446,431	135,356	331,559	13,288	1,212,750
Kevin P. Larson	2014	289,922	286,845	158,639	259,605	4,122,921	5,117,932
Senior Vice	2013	279,435	327,989	142,107	46,725	12,574	808,831
President, Chief Financial Officer	2012	271,713	339,116	128,542	382,204	12,226	1,133,802
Philip J. Dion	2014	236,367	292,582	129,615	100,651	662,457	1,421,672
Senior Vice President, Public Policy and Customer Solutions	2013	199,218	70,005	114,992	16,221	9,363	409,799
Karen G.	2014	219,094	86,054	95,088	325,958	2,272,033	2,998,227
Kissinger	2013	216,627	252,798	107,659	—	10,147	587,230
Vice President and Chief Compliance Officer	2012	213,880	266,857	80,946	270,224	10,019	841,927
Todd C. Hixon Vice President and General Counsel	2014	226,742	86,054	96,072	242,704	460,900	1,112,472

(1) The amounts included in the Summary Compensation Table represent only the amounts paid by UNS for services to TEP and its subsidiaries and do not include amounts paid by UNS for services to others. For 2014 services, 80.46% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2013 services, 79.7% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries. For 2012 services, 78.9% of the amounts paid by UNS were allocable to services to TEP and its subsidiaries.

(2) The amounts in the All Other Compensation column are composed primarily of payments in exchange for stock awards canceled in connection with the Merger, to the extent those awards represent compensation for services to TEP and its subsidiaries. Except for the 2014 awards disclosed in the Stock Awards column, above, all of the awards for which amounts were paid were previously disclosed in the Summary Compensation Table in prior years, and were also disclosed in the table showing Outstanding Equity Awards at Fiscal Year End. Except for the portion allocable to the 2014 awards, shown above, none of the amounts in this column are attributable to awards not previously disclosed.

The amounts in the All Other Compensation column also include Qualified 401 (k) Plan and Non-Qualified Plan Matching Contributions, and also include charitable gifts made on behalf of some Named Executives to a charity of the Named Executive’s choice. These amounts are reported in the year in which the Company committed to the contribution, even though the amount may not have been actually paid until a later year.

Finally, the amounts in the All Other Compensation column include additional payments that Messrs. Larson and Hixon received in 2014. Mr. Larson received a retention bonus in connection with the Merger and as consideration for amending his Change in Control Agreement, as explained in more detail in the section Potential Payments Upon Termination or Change in Control, below. Mr. Hixon received a bonus for his work in connection with the Merger.

Mr. Bonavia's total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $5,460,148, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $4,667.
Mr. Hutchens' total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $2,515,225, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $4,667.
Mr. Larson's total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $3,908,725, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $3,632, and a retention bonus related to the amendment of his Change in Control Agreement of $201,150.
Mr. Dion's total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $651,419, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $1,222, and a $402 charitable contribution.
Ms. Kissinger's total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $2,261,790, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $427, and a $402 charitable contribution.
Mr. Hixon's total listed in the All Other Compensation column for 2014 included payments in exchange for stock awards canceled in connection with the Merger totaling $320,919, qualified plan 401(k) matching contributions of $9,414 and non-qualified plan 401(k) matching contributions of $771, and a bonus for work in connection with the Merger of $129,796.

(3) Mr. Hutchens became TEP's CEO on May 2, 2014, when Mr. Bonavia became the Executive Board Chair.

(4) The amounts included in the Stock Awards column reflect 80.46% of the grant date fair value calculated in accordance with FASB ASC Topic 718 for restricted stock units and performance shares granted in each of the years reported, excluding the effect of forfeitures. Half of the performance share awards had a grant date fair value, based on a Monte Carlo simulation, of $57.47 per share. These awards are based on UNS Energy's compound annualized total shareholder return relative to the companies included in the Edison Electric Institute Utility Index for the three year performance period ended December 31, 2016. The remaining half had a grant date fair value, based on the grant date closing price, of $60.39 per share based on cumulative net income for the performance period ended December 31, 2016. The restricted stock units had a grant date fair value, based on the grant date closing price, of $60.39 per share. The restricted stock units vest on the third anniversary of grant over the vesting period. In the case of performance shares the amounts in the column reflect the grant date fair value assuming the probable outcome of the performance conditions. The 2014 amounts attributable to Restricted Stock Units and Performance Shares are shown on the following table:

	Restricted Stock Units	Performance Shares	Total
Paul J. Bonavia	267,729	522,528	790,257
David G. Hutchens	141,396	275,963	417,359
Kevin P. Larson	97,180	189,665	286,845
Philip J. Dion	99,123	193,459	292,582
Karen G. Kissinger	29,154	56,900	86,054
Todd C. Hixon	29,154	56,900	86,054

If the merger had not occurred, the maximum amount that each person could have received assuming the maximum level of performance and using the fair market value of a share of Company common stock on the grant date ($60.39), would have been: $1,051,522 for Paul Bonavia, $555,341 for David G. Hutchens, $381,677 for Kevin P. Larson, $389,311 for Philip J. Dion, $114,503 for Karen G. Kissinger and $114,503 for Todd C. Hixon.
Pursuant to the terms of the Merger agreement, all outstanding stock awards were canceled in exchange for cash payments in the amounts shown in the appropriate column of the table in Footnote (7) below, providing additional detail for the All Other Compensation column of the Summary Compensation Table, and also shown in Option Exercises and Stock Vested, below.

(5)

The 2014 PEP awards included in this column, pursuant to the terms of the Merger agreement, were paid in 2014 to each of the Named Executives.

(6) Any increase in the present value of the accrued benefit in the Retirement Plan and Excess Benefit Plan is reported in this column. All named executives experienced an increase in the present value of their respective accrued pension benefits during 2014. The present value of accumulated benefits payable is reflected in Pension Benefits, below. UNS Energy does not pay "above market" interest on non-qualified deferred compensation; therefore, this column reflects change in pension value only. See Non-qualified Deferred Compensation, below.

(7) Mr. Bonavia retired from his position as CEO of TEP on May 2, 2014.

GRANTS OF PLAN-BASED AWARDS – 2014

The following table sets forth information regarding plan-based awards by UNS to the Company's Named Executives in 2014 on account of services to TEP and its subsidiaries. As described above, 80.46% of the amount paid by UNS on account of services in 2014 is allocable to services to TEP and its subsidiaries. The compensation plans under which the grants in the following table were made are generally described in Compensation Discussion and Analysis, above and include the PEP, which provides for non-equity (cash) performance awards, and the 2011 Omnibus Plan, which provides for equity-based performance awards including stock options, restricted stock units and performance shares.

	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards[2]			All Other Stock Awards: Number of Shares of Stock or Units[3]	Grant Date Fair Value of Stock and Option Awards[4]
Name		Threshold	Target	Maximum	Threshold	Target	Maximum		
PAUL J. BONAVIA									
PEP	2/24/2014	$214,226	$428,454	$642,680					
Performance Shares	2/24/2014				3,769	8,867	13,300		$522,528
Restricted Stock Units	2/24/2014							4,433	267,729
DAVID G. HUTCHENS									
PEP	2/24/2014	173,794	347,587	521,381					
Performance Shares	2/24/2014				1,991	4,683	7,024		275,963
Restricted Stock Units	2/24/2014							2,341	141,396
KEVIN P. LARSON									
PEP	2/24/2014	72,971	145,942	218,913					
Performance Shares	2/24/2014				1,368	3,218	4,828		189,665
Restricted Stock Units	2/24/2014							1,609	97,180
KAREN G. KISSINGER									
PEP	2/24/2014	43,739	87,477	131,216					
Performance Shares	2/24/2014				410	966	1,448		56,900
Restricted Stock Units	2/24/2014							483	29,154
PHILIP J. DION									
PEP	2/24/2014	59,621	119,242	178,863					
Performance Shares	2/24/2014				1,395	3,283	4,924		193,459
Restricted Stock Units	2/24/2014							1,641	99,123

TODD C. HIXON									
PEP	2/24/2014	44,191	88,382	132,589					
Performance Shares	2/24/2014				410	966	1,448		56,900
Restricted Stock Units	2/24/2014							483	29,154

(1) The amounts shown in this column reflect the range of payouts (50%-150% of the target award) for 2014 performance under the PEP, as described in Compensation Discussion and Analysis - Short-Term Incentive Compensation, above. These amounts are based on the individual’s current salary and position. The amount of cash incentive actually paid under the PEP for 2014 is reflected in the Summary Compensation Table above.

(2) The amounts shown in this column reflect the range (35%-150% of the target award) of payouts in the form of performance shares targeted for 2014 performance under the 2011 Omnibus Plan for long-term incentive compensation, as described in the “Long-Term Incentive Compensation” section of the CD&A, above.

The target 2014 LTI multiples, as a percentage of base salary, are 125% for Mr. Hutchens, 100% for Mr. Larson, 125% for Mr. Dion, 40% for Ms. Kissinger, and 40% for Mr. Hixon. Mr. Dion's 2014 LTI opportunity reflects his contribution to TEP's 2013 rate case and will return to its regular percentage in 2015. The 2014 LTI multiple for Mr. Bonavia, who retired from his position as CEO of TEP on May 2, 2014, was 150% of base salary. The target LTIP award was granted partly in the form of performance shares and partly in the form of restricted stock units, with 67% of the value in the form of performance shares and the remaining 33% in the

form of restricted stock units. Accordingly, each Named Executive received an LTIP target award of performance shares and restricted stock units the total value of which was equal to the executive's base salary multiplied by the applicable multiple (e.g., 100% for CFO), divided by the grant date fair market value of a share of UNS Energy's common stock ($60.39), rounded down to the nearest 10 shares. For example, the CFO's 2014 base salary (and LTIP target award) was $362,769. That amount divided by $60.39, and rounded down to the nearest 10 shares, resulted in an LTIP target award of 4,000 performance shares and 2,000 restricted stock units.
The 2014 awards of performance shares and restricted stock units were intended to issue shares at the end of the performance period depending on the Company's performance relative to the two performance criteria described in Compensation Discussion and Analysis, above. The two performance criteria operate independently; a Named Executive would have received a payment on account of one of the criteria without regard to performance on the other criteria. However, pursuant to the terms of the Merger agreement, the 2014 stock awards were canceled in exchange for cash payments as shown in Option Exercised and Stock Vested, below.

(3) The amounts shown in this column represent the number of time-based restricted stock units that were granted in 2014 under the 2011 Omnibus Plan.

(4) The amounts shown in this column represent the grant date fair value calculated in accordance with FASB ASC Topic 718. The amounts shown for performance shares are based on the probable outcome of performance conditions. Half of the performance share awards had a grant date fair value, based on a Monte Carlo simulation, of $57.47 per share. These awards are based on UNS Energy's compound annualized total shareholder return relative to the companies included in the Edison Electric Institute Utility Index for the three year performance period ended December 31, 2016. The remaining half had a grant date fair value, based on the grant date closing price, of $60.39 per share based on cumulative net income for the performance period ended December 31, 2016. The restricted stock units had a grant date fair value, based on the grant date closing price, of $60.39 per share. The restricted stock units vest on the third anniversary of grant over the vesting period. For more information about these awards, please refer to footnote 1 of the Summary Compensation Table and Compensation Discussion and Analysis, above.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END - 2014

There were no equity awards outstanding at the end of 2014. All outstanding equity awards were canceled in exchange for cash at the time of the Merger.

OPTION EXERCISES AND STOCK VESTED

The following table includes certain information with respect to the disposition by the Company's Named Executives of outstanding stock options and stock awards that vested during the year ended December 31, 2014. The awards were originally issued by UNS Energy for services to UNS Energy and all of its subsidiaries. Only a portion of the awards represented compensation for services to TEP and its subsidiaries, which was 80.46% in 2014.

	Option Awards		Stock Awards (2)	
	Number of Shares Acquired on Exercise	Value Realized on Exercise(1)	Number of Shares Acquired on Vesting	Value Realized on Vesting
Paul J. Bonavia	48,228	$ 1,646,494	87,486.7	$ 5,270,103
David G. Hutchens	21,990	650,358	33,623.4	2,025,704
Kevin P. Larson	80,798	2,524,679	31,755.6	1,912,920
Philip J. Dion	3,412	116,469	10,760.0	648,213
Karen G. Kissinger	44,173	1,324,742	22455.3.	1,352,657
Todd C. Hixon	—	—	5,326.5	320,919

(1) Pursuant to the Merger agreement, all outstanding stock options were cancelled in exchange for a cash payment per share equal to the difference between the option exercise price and $60.25 pursuant to the Merger agreement.

(2) The amounts shown in the Stock Awards columns of the table above include 80.46% of the performance shares earned for the 2011-2013 performance period, payment of which the Compensation Committee approved on February 6, 2014 and paid in shares of Company stock on February 14, 2014. The table below shows the number of performance shares that vested and the value realized on vesting, calculated using the fair market value of a

share of Company stock on February 14, 2014 ($60.21).

	Number of Shares Acquired on Vesting	Value Realized on Vesting
Paul J. Bonavia	24,189.5	$1,456,449
David G. Hutchens	2,671.3	160,837
Kevin P. Larson	8,783.8	528,873
Philip J. Dion	1,881.2	113,264
Karen G. Kissinger	6,902.7	415,609

The amounts shown in the Stock Awards columns of the table above also include 80.46% of the total amounts paid, pursuant to the terms of the Merger agreement, for (i) all outstanding performance shares for the 2012-2014 performance period, the 2013-2015 performance period and the 2014-2016 performance period, and (ii) all outstanding restricted stock units. The per share value realized was $60.25, the price paid under the Merger.

	Number of Shares Acquired on Vesting	Value Realized on Vesting
Paul J. Bonavia	63,297.2	$3,813,654
David G. Hutchens	30,952.2	1,864,867
Kevin P. Larson	22,971.7	1,384,046
Philip J. Dion	8,878.8	534,950
Karen G. Kissinger	15,552.7	937,048
Todd C. Hixon	5,326.5	320,919

PENSION BENEFITS

The following table shows 80.46% of the present value of accumulated benefits payable to each of the Named Executives, including the number of years of service credited to each such Named Executive, under each of the Retirement Plan and the Excess Benefit Plan determined using interest rate and mortality rate assumptions used in the Company's financial statements. See Note 8 of Notes to Consolidated Financial Statements. Information regarding the Retirement Plan and the Excess Benefit Plan can be found above in Retirement and Other Benefits.

	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
Paul J. Bonavia	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	5.75	$ 225,777	$ —
	Tucson Electric Power Excess Benefit Plan(2)(3)	5.75	811,940	—
David G. Hutchens	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	19.50	741,593	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	19.50	812,778	—
Kevin P. Larson	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	29.83	1,296,566	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	29.83	1,412,277	—
Philip J. Dion	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	6.83	150,201	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	6.83	68,941	
Karen G. Kissinger	Tucson Electric Power Salaried Employees Retirement Plan(1)(3)	24	1,183,911	—
	Tucson Electric Power Excess Benefit Plan(2)(3)	24	716,043	—
Todd C. Hixon	Tucson Electric Power Salaried Employees Retirement Plan			