TUCSON ELECTRIC POWER CO
Form 10-K
February 16, 2017

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, 2016
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 xSmaller 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 February 15, 2017, 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, an indirect wholly owned subsidiary of Fortis Inc.
Documents incorporated by reference: None
Tucson Electric Power meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

Table of Contents

Definitions	v
Forward-Looking Information	vii
PART I	
Item 1. Business	1
Overview of Business	1
Environmental Matters	9
Employees	9
Executive Officers of the Registrant	10
SEC Reports Available on TEP's Website	10
Item 1A. Risk Factors	10
Item 1B. Unresolved Staff Comments	14
Item 2. Properties	15
Item 3. Legal Proceedings	16
Item 4. Mine Safety Disclosures	16
PART II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities	17
Item 6. Selected Financial Data	17
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	18
Critical Accounting Policies	33
Recently Issued Accounting Pronouncements	37
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	37
Item 8. Consolidated Financial Statements and Supplementary Data	41
Management's Report on Internal Control Over Financial Reporting	41
Reports of Independent Registered Public Accounting Firm	42
Consolidated Statements of Income	43
Consolidated Statements of Comprehensive Income	44
Consolidated Statements of Cash Flows	45
Consolidated Balance Sheets	46
Consolidated Statements of Changes in Stockholder's Equity	48
Notes to Consolidated Financial Statements	49
Note 1. Nature of Operations and Summary of Significant Accounting Policies	49
Note 2. Regulatory Matters	55
Note 3. Utility Plant and Jointly-Owned Facilities	58
Note 4. Accounts Receivable	60
Note 5. Related Party Transactions	61
Note 6. Debt, Credit Facility, and Capital Lease Obligations	62
Note 7. Commitments and Contingencies	65
Note 8. Employee Benefit Plans	69
Note 9. Share-Based Compensation	75
Note 10. Supplemental Cash Flow Information	76
Note 11. Fair Value Measurements and Derivative Instruments	77
Note 12. Income Taxes	81
Note 13. Recently Issued Accounting Pronouncements	83
Note 14. Quarterly Financial Data (Unaudited)	83

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	84
Item 9A. Controls and Procedures	84
Item 9B. Other Information	84

PART III

Item 10. Directors, Executive Officers, and Corporate Governance	85
Item 11. Executive Compensation	85
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	85
Item 13. Certain Relationships and Related Transactions and Director Independence	85
Item 14. Principal Accounting Fees and Services	85

PART IV

Item 15. Exhibits, Financial Statement Schedules	87
Item 16. Form 10-K Summary	87
Signatures	88
Exhibit Index	89

DEFINITIONS

The abbreviations and acronyms used in the 2016 Form 10-K are defined below:

2010 Reimbursement Agreement	Reimbursement Agreement, dated December 14, 2010, between TEP, as borrower, and a financial institution
2013 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective July 1, 2013
2017 Rate Order	A rate order issued by the ACC resulting in a new rate structure for TEP, effective on or before on or before March 1, 2017
ACC	Arizona Corporation Commission
APS	Arizona Public Service Company
BART	Best Available Retrofit Technology
BBtu	Billion British thermal unit(s)
CDD	Cooling Degrees Days is an index used to measure the impact of weather on power usage calculated by subtracting 75 from the average of the high and low daily temperatures
DG	Distributed Generation
DSM	Demand Side Management
EE Standards	Energy Efficiency Standards
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Fortis	Fortis Inc., a corporation incorporated under the Corporations Act of Newfoundland and Labrador, Canada, whose principal executive offices are located at Fortis Place, Suite 1100, 5 Springdale Street, St. John's, NL A1E 0E4
Four Corners	Four Corners Generating Station
GAAP	Generally Accepted Accounting Principles in the United States of America
Gila River	Gila River Generating Station
GWh	Gigawatt-hour(s)
HDD	Heating Degrees Days is an index used to measure the impact of weather on power 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(s) of Credit
Luna	Luna Generating Station
MATS	Mercury and Air Toxics Standards
MMBtu	Million British thermal units
MW	Megawatt(s)
MWh	Megawatt-hour(s)
Navajo	Navajo Generating Station
NBV	Net Book Value
PNM	Public Service Company of New Mexico
PPA	Power Purchase Agreement
PPFAC	Purchased Power and Fuel Adjustment Clause
REC	Renewable Energy Credit
Regional Haze Rules	Rules promulgated by the EPA to improve visibility at national parks and wilderness areas
RES	Renewable Energy Standard
Retail Rates	Rates designed to allow a regulated utility to recover its costs of providing services and an opportunity to earn a reasonable return on its investment
San Juan	San Juan Generating Station
SCR	Selective Catalytic Reduction

v

SES	Southwest Energy Solutions, Inc.
SJCC	San Juan Coal Company
SNCR	Selective Non-Catalytic Reduction
Springerville	Springerville Generating Station
SRP	Salt River Project Agricultural Improvement and Power District
Sundt	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 Alterna Springerville LLC (Alterna) and LDVF1 TEP LLC (LDVF1) (Alterna and LDVF1, together with the Owner Trustees and Co-trustees, the Third-Party Owners)
TSA	Transmission Service Agreement
Tri-State	Tri-State Generation and Transmission Association, Inc.
UES	UniSource Energy Services, Inc., a wholly-owned subsidiary of UNS Energy Corporation, and intermediate holding company established to own the operating companies UNS Electric, Inc. and UNS Gas, Inc.
UNS Electric	UNS Electric, Inc., an indirect wholly-owned subsidiary of UNS Energy Corporation
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 Corporation including UniSource Energy Services Inc., 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 Company (TEP or the Company) 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 TEP in this Annual Report on Form 10-K. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events, future operational, economic, or financial performance and underlying assumptions, and other statements that are not statements of historical facts. Forward-looking statements may be identified by the use of words such as anticipates, believes, estimates, expects, intends, may, plans, predicts, projects, would, and similar expressions. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All such forward-looking statements, whether written or oral, and whether made by or on behalf of TEP, are expressly qualified by these cautionary statements and any other cautionary statements which may accompany the forward-looking statements. In addition, TEP disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report, except as may otherwise be required by the federal securities laws.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed therein. We express our estimates, expectations, beliefs, and projections in good faith and believe them to have a reasonable basis. However, we make no assurances that management’s estimates, 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 of Financial Condition and Results of Operations; and other parts of this report. These factors include: state and federal regulatory and legislative decisions and actions, including changes in tax policies; changes in, and compliance with, environmental laws and regulations, decisions and policies that could increase operating and capital costs, reduce generation facility output or accelerate generation 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 and bank 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 potential inability to make additions to our existing high voltage transmission system; unexpected increases in operations and maintenance expense; resolution of pending litigation matters; changes in accounting standards; changes in our critical accounting policies and estimates; the ongoing impact of mandated energy efficiency and distributed generation initiatives; changes to long-term contracts; the cost of fuel and power supplies; the ability to obtain coal from our suppliers; cyber attacks, data breaches, or other challenges to our information security, including our operations and technology systems; and the performance of TEP's generation facilities.

PART I
ITEM 1. BUSINESS
OVERVIEW OF BUSINESS
General
TEP and its predecessor companies have served the greater Tucson metropolitan area for almost 125 years. TEP was incorporated in the State of Arizona in 1963. TEP is a regulated electric utility company serving approximately 420,000 retail customers. TEP’s service territory covers 1,155 square miles and includes a population of approximately 1,200,000 people in Pima County, as well as parts of Cochise County. TEP's principal business operations include generating, transmitting, and distributing electricity to its retail customers. In addition to retail sales, TEP sells electricity, transmission, and ancillary services to other utilities, municipalities, and energy marketing companies on a wholesale basis. TEP is subject to comprehensive state and federal regulation. The regulated electric utility operation is TEP's only segment.
TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. In August 2014, UNS Energy was acquired by Fortis Inc. (Fortis) and became an indirect wholly owned subsidiary of Fortis which is a leader in the North American electric and gas utility business.
Regulated Utility Operations
TEP delivers electricity to retail customers in southern Arizona. TEP owns or has contracts for coal, natural gas, wind, and solar generation resources to provide electricity. This electricity, together with electricity purchased on the wholesale market, is delivered over transmission lines which are part of the Western Interconnection, a regional grid in the United States. The electricity is then transformed to lower voltages and delivered to customers through TEP's distribution system.
TEP operates under a certificate of public convenience and necessity as regulated by the Arizona Corporation Commission (ACC), under which TEP is obligated to provide electricity service to customers within its service territory. Retail rates are rates designed to allow a regulated utility to recover its costs of providing services and an opportunity to earn a reasonable return on its investment (Retail Rates). The ACC establishes Retail Rates.
Customers
Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers over the last three years were as follows:

(sales in GWh)	2016			2015			2014		
Electric Sales									
Residential	3,724	29	%	3,724	28	%	3,727	29	%
Commercial	2,139	17	%	2,124	15	%	2,170	17	%
Industrial, non-Mining	2,006	16	%	2,063	15	%	2,098	16	%
Industrial, Mining	997	8	%	1,109	8	%	1,137	9	%
Other	30	—	%	33	—	%	33	—	%
Total Retail Sales by Customer Class	8,896	70	%	9,053	66	%	9,165	71	%
Long-Term Wholesale Sales	463	4	%	750	5	%	618	5	%
Short-Term Wholesale Sales	3,308	26	%	3,928	29	%	3,082	24	%
Total Electric Sales	12,667	100	%	13,731	100	%	12,865	100	%
Average Number of Retail Customers									
Residential	378,991	90	%	376,439	90	%	374,204	90	%
Commercial	38,403	9	%	38,253	9	%	38,079	9	%
Industrial, non-Mining	580	—	%	588	—	%	604	—	%
Industrial, Mining	4	—	%	4	—	%	4	—	%
Other	1,866	1	%	1,857	1	%	1,858	1	%
Total Retail Customers	419,844	100	%	417,141	100	%	414,749	100	%

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 customer-sited Distributed Generation (DG).
Local, regional, and national economic factors impact the growth in the number of customers in TEP’s service territory. In each of the past five years, TEP’s average number of retail customers increased by less than 1%. TEP expects the number of retail customers to increase at a rate of approximately 1% in 2017 based on the estimated population growth in its service territory.
TEP’s retail sales volume in 2016 was 8,896 gigawatt-hours (GWh), which is a decrease of 4% from 2012 levels. During the past five years, local economic conditions combined with state requirements to reduce retail sales through energy efficiency and DG have resulted in lower sales volumes and lower use per customer.
Two of TEP’s largest retail customers are in the copper mining industry. TEP’s GWh sales to mining customers depend on a variety of factors including commodity prices, electricity prices, and the mines’ development of self-generating resources. TEP’s GWh sales to mining customers decreased by 10% in 2016 as a result of mining curtailments due to declining commodity prices. TEP cannot predict how long the commodity prices will remain low or the impact prices will have on mining production and any resulting impact commodity prices may have on TEP's GWh sales.
See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations of this Form 10-K for additional information regarding mining customers.
Wholesale Customers
TEP’s 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.
Generally, TEP commits to future sales based on expected generation 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:
Long-Term Wholesale Sales
Contracts for long-term wholesale sales cover periods of one year or greater. TEP typically uses its own generation to serve the requirements of its long-term wholesale customers.
TEP’s long-term wholesale contract with Salt River Project Agricultural Improvement and Power District (SRP) expired in May 2016. TEP's current primary long-term wholesale sale contracts customers are presented in the table below:

	Contracts Expire December 31,
Shell Energy North America	2017
Navajo Tribal Utility Authority	2022
TRICO Electric Cooperative	2024
Navopache Electric Cooperative	2041

Short-Term Wholesale Sales
Forward contracts commit TEP to sell a specified amount of capacity or power at a specified price over a given period of time, typically for one-month or three-month periods. TEP also engages in short-term sales by selling power in the daily or hourly markets at fluctuating spot market prices and making other non-firm power sales. The majority of our 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.

Competition

Retail Customers

TEP is the primary electric service provider to retail customers within its service territory and operates under a certificate of public convenience and necessity as regulated by the ACC.

Wholesale Customers

The Federal Energy Regulatory Commission (FERC) regulates rates for wholesale power sales and transmission services. TEP engages in long-term wholesale sales to optimize its generation resources. As a result of its wholesale power activity, TEP competes with other utilities, power marketers, and independent power producers in the wholesale markets.

Generation Facilities

As of December 31, 2016, TEP owned 2,696 megawatts (MW) of nominal generation capacity, as set forth in the following table. Nominal capacity is based on unit design net output, and measured in direct current (DC).

	Unit		Date	Resource	Capacity	Operating	TEP's Share	
Generation Source	No.	Location	In Service	Type	MW	Agent	%	MW
Springerville Station (1)	1	Springerville, AZ	1985	Coal	387	TEP	100	387
Springerville Station (2)	2	Springerville, AZ	1990	Coal	406	TEP	100	406
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	81
Sundt Station	2	Tucson, AZ	1960	Gas/Oil	81	TEP	100	81
Sundt Station	3	Tucson, AZ	1962	Gas	104	TEP	100	104
Sundt Station	4	Tucson, AZ	1967	Gas	156	TEP	100	156
Sundt Internal Combustion Turbines		Tucson, AZ	1972-1973	Gas/Oil	50	TEP	100	50
DeMoss Petrie		Tucson, AZ	2001	Gas	75	TEP	100	75
North Loop		Tucson, AZ	2001	Gas	94	TEP	100	94
Springerville Solar Station		Springerville, AZ	2002-2014	Solar	16	TEP	100	16
Tucson Solar Projects		Tucson, AZ	2010-2014	Solar	13	TEP	100	13
Ft. Huachuca Project (3)		Ft. Huachuca, AZ	2014	Solar	17	TEP	100	17
Total TEP Capacity (4)								2,696

(1) In 2016, TEP purchased a 50.5% undivided interest in Unit 1 of the Springerville Generating Station (Springerville) increasing its total ownership interest to 100%. See Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information related to the Springerville Unit 1 settlement.

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

(3) In January 2017, a second phase of the Ft. Huachuca Project was commissioned adding 5 MW of solar generation to TEP's total generation capacity.

(4) Excludes 781 MW of additional resources, which consist of certain capacity purchases and interruptible retail load.

3

Springerville Generating Station

TEP's other interests in Springerville include: (i) a 100% undivided interest in certain common facilities at Springerville (Springerville Common Facilities), that includes assets such as, but not limited to: administration building, roads, and well fields used to serve all four units at Springerville that cannot be proportioned to each unit; and (ii) an 82.95% ownership interest in the Springerville Coal Handling Facilities.

Springerville Common Facilities Leases

TEP holds leveraged lease arrangements related to a 50% undivided interest in Springerville Common Facilities that are scheduled to expire in December 2017 and January 2021. In December 2016, TEP notified the owner participant and the lessor of the lease scheduled to expire in December 2017 that TEP had elected to purchase an undivided ownership interest in the Springerville Common Facilities at the fixed purchase price of $38 million upon the expiration of the lease term. The leases scheduled to expire in January 2021 each have fair market value renewal options as well as fixed-price purchase options. The fixed prices to acquire the leased interests in January 2021 are $68 million.

See Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources and Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding the capital leases and the purchase commitment.

Springerville Units 3 and 4

Springerville Units 3 and 4 are each approximately 400 MW coal-fired generation facilities that are operated, but not owned by TEP. These facilities are located at the same site as Springerville Units 1 and 2. The lessee of Springerville Unit 3 compensates TEP for operating the facilities and pays an allocated portion of the fixed costs related to the Springerville Common Facilities and Springerville Coal Handling Facilities. The owner of Springerville Unit 4 owns 17.05% of the Springerville Coal Handling Facilities and pays TEP for a portion of the fixed costs allocated for the common facilities.

Renewable Energy Resources

The ACC’s Renewable Energy Standard (RES) requires Arizona regulated utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with DG accounting for 30% of the annual renewable energy requirement. TEP must file an annual RES implementation plan for review and approval by the ACC. TEP plans to meet these requirements through a combination of utility owned resources, Power Purchase Agreements (PPAs), and customer-sited DG. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K and Rates and Regulations below for additional information regarding RES.

Owned Renewable Resources

As of December 31, 2016, TEP owned 46 MW of photovoltaic (PV) solar generation capacity measured in DC. In January 2017, TEP completed an additional solar project adding 5 MW of PV solar generation capacity. The solar generation facilities are located on properties held under easements and leases.

Renewable Power Purchase Agreements

As of December 31, 2016, TEP had renewable PPAs for 196 MW of capacity measured in DC from solar resources, 80 MW of capacity measured in alternating current (AC) from wind resources and 4 MW of capacity measured in AC from a landfill gas generation facility. The solar PPAs contain options that allow TEP to purchase all or part of the related project at a future date.

Purchased Power

TEP purchases power from other utilities and power marketers. TEP may enter into contracts to purchase: (i) power under long-term contracts to serve retail load and long-term wholesale contracts; (ii) capacity or power during periods of planned outages or for peak summer load conditions; and (iii) power for resale to certain wholesale customers under load and resource management agreements. See Note 7 of Notes to Consolidated Financial Statements related to the commitment amount of purchased power in Part II, Item 8 of this Form 10-K.

TEP typically uses generation from its natural gas-fired units, supplemented by purchased power, to meet the summer peak demands of its retail customers. Due to its increasing natural gas and purchased power usage, TEP hedges a portion of its total energy price exposure with forward priced contracts for a maximum of three years. Certain of these contracts are at a fixed price per MWh and others are indexed to natural gas prices. TEP also purchases power 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 power.

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 facility outages and system disturbances, and reduce the amount of reserves TEP is required to carry.

Peak Demand and Future Resources

Peak Demand

(in MW)	2016	2015	2014	2013	2012
Retail Customers	2,278	2,222	2,218	2,230	2,290

In 2016, TEP's generation and purchased resources were sufficient to meet total retail and long-term wholesale peak demand, while maintaining a reserve margin in compliance with reliability criteria set forth by the Western Electricity Coordinating Council, a regional council of North American Reliability Corporation (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, energy conservation, DG, economic conditions, and other factors. Retail peak demand in 2016 increased due to unseasonably hot weather. From 2012-2015, retail peak demand was negatively impacted by weak economic conditions, the implementation of energy efficiency programs, and an increased level of customer-installed DG.

Forecasted retail peak demand for 2017 is 2,233 MW compared with actual peak demand of 2,278 MW in 2016. TEP’s 2017 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 that existing generation capacity and PPAs are sufficient to meet the expected demand and reserve margin requirements in 2017.

Future Resources

As of December 31, 2016, approximately 52% of TEP's generation capacity is coal-fired generation. TEP is executing strategies and evaluating additional steps to reduce its dependency on coal-fired generation while still meeting its peak load requirements and maintaining affordable Retail Rates.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations of this Form 10-K for additional information regarding TEP's generation resources.

Fuel Supply

A summary of Fuel and Purchased Power resource information is provided below:

	Average Cost (cents per kWh)			Percentage of Total kWh Resources		
	2016	2015	2014	2016	2015	2014
Coal	2.30	2.44	2.50	62 %	60 %	68 %
Gas	2.84	3.35	4.99	25 %	19 %	9 %
Purchased Power, Non-Renewable	3.43	3.04	4.14	8 %	18 %	21 %
Purchased Power, Renewable	7.00	9.82	10.50	5 %	3 %	2 %
All Resources	3.15	3.31	3.64	100 %	100 %	100 %

Coal

The coal used 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 generation stations. The average cost of coal per million metric British thermal unit (MMBtu), including transportation, was $2.21 in 2016, $2.34 in 2015, and $2.43 in 2014.

Station	Coal Supplier	2016 Coal Consumption (tons in 000s)	Contract Expiration	Average Sulfur Content	Coal Obtained From
Springerville	Peabody CoalSales [(1)]	2,706	2020	1.0%	Lee Ranch Mine/El Segundo Mine
Four Corners	NTEC [(2)]	260	2031	0.8%	Navajo Mine
San Juan	San Juan Coal Co. [(3)]	1,212	2022	0.8%	San Juan Mine
Navajo	Peabody CoalSales [(1)]	433	2019	0.6%	Kayenta Mine

(1) In April 2016, Peabody Energy Corp. (Peabody) filed for reorganization under Chapter 11 of the Bankruptcy Code. TEP has continued to receive its contracted coal as planned and believes it has sufficient access to coal inventory for the near future. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to Peabody's bankruptcy.

(2) Beginning in July 2016 through June 2031, the coal for the Four Corners Generating Station (Four Corners) is being purchased from the Navajo Transitional Energy Company (NTEC). NTEC purchased the mine located near Four Corners from BHP Billiton and began overseeing the mine operation in 2016.

(3) BHP Billiton sold San Juan Coal Company (SJCC) to Westmoreland Coal Company (WCC), effective January 31, 2016.

Coal-Fired Generation Facilities Operated by TEP

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 remaining lives.

Coal-Fired Generation Facilities Operated by Others

TEP also participates in jointly-owned coal-fired generation facilities at 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 generation facilities located adjacent to the coal reserves. Navajo, which is operated by SRP, obtains its coal supply from the nearby Kayenta coal mine and receives deliveries on a dedicated electric rail delivery system. In 2016, WCC purchased SJCC from BHP Billiton and entered into a new coal supply agreement for San Juan with the operator, PNM. The new coal supply agreement has an expiration date of June 2022. TEP expects coal reserves available to these three jointly-owned generation facilities to be sufficient for the remaining lives of the stations.

Natural Gas Supply

TEP uses generation from its facilities fueled by natural gas, in addition to power from its coal-fired generation facilities and purchased power, to meet the summer peak demands of its retail customers and local reliability needs. The average cost of natural gas per MMBtu, including transportation, was $3.14 in 2016, $3.49 in 2015, and $5.17 in 2014.

TEP has long-term firm agreements with El Paso Natural Gas (EPNG) for transportation from the Permian and San Juan Basins to Sundt under firm transportation agreements. TEP also purchases firm gas transportation for Unit 3 of the Gila River Generating Station (Gila River) from EPNG and Transwestern Pipeline Co., and for the Luna Generating Station (Luna) from EPNG. TEP purchases natural gas from Southwest Gas Corporation under a retail tariff for the North Loop Generating Station's (North loop) 94 MW of internal combustion turbines and receives distribution service under a transportation agreement for DeMoss Petrie Generating Station's (DeMoss Petrie) 75 MW internal combustion turbine.

Transmission and Distribution

TEP's transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. TEP's transmission system, together with contractual rights on other transmission systems, enables TEP to integrate and access generation resources to meet its customer load requirements.

TEP's transmission and distribution systems included approximately 2,170 miles of transmission lines and 7,590 miles of distribution lines as of December 31, 2016.

Rates and Regulations

The ACC and the FERC each regulate portions of 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.

See Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Factors Affecting Results of Operations and Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this From 10-K for additional information that relates to rates and regulations that affect TEP including key provisions of its 2017 Rate Order.

2017 Rate Order

In February 2017, the ACC issued a rate order in the rate case filed by TEP in November 2015. TEP's rate filing was based on a test year ended June 30, 2015 (2017 Rate Order). The 2017 Rate Order authorizes an annual increase in non-fuel revenue requirements of $81.5 million. New billing rates will be effective starting on or before March 1, 2017.

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 forward component adjusts for any costs over or under base fuel collection rates expected over a 12-month period. The true-up component reconciles any over/under collected amounts from the preceding 12-month period and is calculated to credit or recover these amounts 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 sulfur dioxide (SO_2) emissions; sulfur credits received from TEP’s coal suppliers; broker fees; revenues from short-term wholesale sales; all of the proceeds from the sale of SO_2 allowances; and all other costs as allowed by the ACC.

As of December 31, 2016, TEP had over-collected fuel and purchased power costs by $38 million.

Renewable Energy Standard and Tariff

The ACC’s RES requires Arizona 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 DG accounting for 30% of the annual renewable energy requirement. Affected utilities must file an annual RES implementation plan for review and approval by the ACC. The approved costs of carrying out those plans is recovered from retail customers through the RES surcharge until such costs are reflected in TEP’s non-fuel base rates. The associated lost revenues attributable to meeting distributed generation targets will be partially recovered through the Lost Fixed Cost Recovery Mechanism (LFCR).

In May 2016, the ACC approved TEP's 2016 RES implementation plan of $57 million, which was partially offset by applying approximately $9 million of previously recovered carryover funds. TEP will recover the remaining $48 million through the RES surcharge. The recovery will fund the following: (i) the above market cost of renewable power purchases; (ii) previously awarded performance-based incentives for customer installed DG; (iii) depreciation and a return on certain TEP investments in company-owned solar projects; and (iv) various other program costs. TEP recognized approximately $3 million of revenue in 2016 as a return on company-owned solar projects. TEP suspended its rooftop solar program effective December 2016, but requested approval of a community solar program. The ACC is expected to consider this program in a second phase of TEP’s rate case proceedings (Phase 2).

In July 2016, TEP submitted an application for the 2017 RES implementation plan with a budget amount of $54 million. TEP expects to recover less than $1 million of revenue in 2017 through the RES surcharge as a return on certain company-owned solar projects. This amount reflects the return and related recovery on projects that are not included in TEP’s Retail Rates. In addition, TEP is no longer requesting recovery on company-owned solar projects through the RES mechanism. TEP expects to receive a decision on its 2017 RES implementation plan in first half of 2017.

The percentage of retail kilowatt-hour (kWh) sales attributable to the 2016 RES renewable energy requirement was approximately 10%, exceeding the overall 2016 requirement of 6%. TEP expects to meet the 2017 RES renewable energy requirement of 7% of retail kWh sales. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation Renewable Energy Credits (REC), which are used to demonstrate compliance with the DG requirement, the ACC approved a waiver of the 2016 and 2017 residential DG requirement.

Energy Efficiency Standards

Under the Energy Efficiency Standards (EE Standards), the ACC requires electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. As of December 2016, TEP’s cumulative annual energy savings was approximately 12%. Compliance with the EE Standards is governed by the ACC’s approval of TEP's annual implementation plan.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan, including recovery of approximately$14 million from retail customers for new and existing DSM programs. Energy savings realized through the programs will count toward meeting the EE Standards and the associated lost revenue will be partially recovered through the LFCR mechanism. TEP notified the ACC that it would not file a 2017 implementation plan and will continue its 2016 plan through the end of 2017 without change. TEP expects to file its 2018 implementation plan by June 1, 2017.

Distributed Generation

In 2016, the ACC held proceedings under the Value and Cost of Distributed Generation (Value of DG) docket to examine the ACC’s net metering rules and determine the value that utilities should pay DG customers who deliver electricity from rooftop solar systems back to the grid. Prior to this proceeding, the ACC’s net metering rules allowed DG customers who over-produced electricity to carry-over or “bank” excess electricity at a value equal to the full retail rate per kWh. Banked kWh could then be used by the customer to offset future energy usage that could not be met by their DG system.

In December 2016, the ACC approved an order that will begin to reform net metering in Arizona. The order adopts a number of net metering changes and policies, including:

- placing DG customers in a separate rate class;
- grandfathering current DG customers under net metering rules and rate design for 20 years from interconnection application;
- eliminating the banking of excess kWh for non-grandfathered DG customers; and
- compensating non-grandfathered customers for their exported kWh based on the DG export rate in effect at the time of interconnection.

The initial compensation for DG exports will be based on a five-year historical average cost per kWh of TEP’s portfolio of owned and contracted utility-scale solar projects, and will be established in Phase 2. The DG export rate will be updated annually and customers adopting solar will be compensated for 10 years at the rate in effect at the time they file an application for interconnection. An avoided cost methodology will also be developed for potential use in TEP’s next rate case.

FERC Compliance

In 2015 and 2016, TEP self-reported to the FERC Office of Enforcement (OE) that TEP had not timely filed certain FERC-jurisdictional agreements. TEP conducted comprehensive internal reviews of its compliance with the FERC filing requirements (Compliance Reviews), and made compliance filings with the FERC Office of Energy Market Regulation. This included the filing of several TSAs entered into between 2003 and 2015 that contained certain deviations from TEP’s standard form of service agreement.

In 2016, the FERC issued orders related to the late-filed Transmission Service Agreements (TSA), which directed TEP to issue time value refunds to the counterparties to these TSAs (FERC Refund Orders). As a result of the FERC Refund Orders and ongoing discussions with the OE, TEP recorded $22 million in time value refunds in 2016. Of the total amount recorded, TEP paid $17 million in 2016 and accrued the remaining $5 million as of December 31, 2016.

In June 2016, to preserve its rights, TEP petitioned the D.C. Circuit Court of Appeals to review the FERC Refund Orders. In January 2017, TEP and one of the TSA counterparties entered into a settlement. Under the settlement, the counterparty paid TEP $8 million in January 2017 and TEP dismissed the appeal with prejudice. See Note 7 of

Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information related to the FERC Refund Orders.

ENVIRONMENTAL MATTERS

The Environmental Protection Agency (EPA) regulates the amount of SO_2, nitrogen oxide (NO_x), carbon dioxide (CO_2), particulate matter, mercury, and other by-products produced by generation facilities. TEP may incur added costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its generation facilities. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. TEP expects to recover the cost of environmental compliance through Retail Rates.

National Ambient Air Quality Standards

In October 2015, the EPA released the final rule for the 8-hour U.S. National Ambient Air Quality Standards (NAAQS) for ozone (O_3). The EPA lowered the standard from 75 parts per billion (ppb) to 70 ppb. If Pima County does not meet the standard, the county will be designated as a “non-attainment” area and will need to develop a plan to bring the air-shed into compliance. A “non-attainment” designation may slow economic growth in the region and impact our ability to site new local generation. The States’ recommendation of area designations (attainment, non-attainment, or unclassified) was submitted in September 2016 and Pima County was designated as an attainment area.

Implementation of the rule is scheduled as follows:

- EPA's response to the States’ designation recommendations by June 2017.
- EPA's finalization of area designations by October 2017, based on 2014-2016 air quality data.

Effluent Limitation Guidelines

In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines (ELG) setting standards and limitations for steam electric generation facility discharges. The ELG rule establishes discharge limits for fly ash and mercury contaminated wastewater at those facilities that require a National Pollution Discharge Elimination System (NPDES) with an effective date between November 2018 and November 2023. With the exception of Four Corners, none of the other TEP owned facilities require a NPDES permit and therefore are not affected. With regard to Four Corners, until a draft NPDES permit is proposed during the 2018-2023 timeframe, we cannot predict what will be required to control these discharges to be in compliance with the finalized effluent limitations at that facility. TEP does not anticipate a significant financial impact from these requirements.

TEP believes it is in material compliance with applicable environmental laws and regulations. Refer to Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, Environmental Laws and Regulations of this Form 10-K for additional information related to environmental laws and regulations impacting TEP's liquidity and capital resources and Liquidity and Capital Resources for TEP's forecasted environmental-related capital expenditures.

EMPLOYEES

As of December 31, 2016, TEP had 1,508 employees, of which approximately 686 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 2016 and expires in December 2018.

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, as of January 2, 2017, are as follows:

Name	Age	Position(s) Held	Executive Officer Since
David G. Hutchens [(1)]	50	President and Chief Executive Officer	2007
Kevin P. Larson	60	Senior Vice President	1997
Frank P. Marino [(1)(2)]	52	Vice President and Chief Financial Officer	2013
Kentton C. Grant [(3)]	58	Vice President, Rates and Planning	2007
Susan M. Gray	44	Vice President of Energy Delivery	2015
Todd C. Hixon [(1)]	50	Vice President and General Counsel	2011
Karen G. Kissinger	62	Vice President and Chief Compliance Officer	1991
Mark C. Mansfield	61	Vice President, Energy Resources	2012
Catherine E. Ries	57	Vice President, Customer and Human Resources	2007
Mary Jo Smith	59	Vice President, Public Policy	2015
Morgan C. Stoll [(4)]	46	Vice President and Chief Information Officer	2016
Martha B. Pritz [(5)]	55	Treasurer	2016
Herlinda H. Kennedy	55	Corporate Secretary	2006

(1) Member of the TEP Board of Directors. 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.

(2) Frank P. Marino was named Vice President and Chief Financial Officer effective January 2, 2017. The appointment was subsequent to the announcement in November 2016 of the retirement of Kevin P. Larson, TEP's former Chief Financial Officer, in 2017.

(3) In November 2016, Kentton C. Grant was named Vice President of Rates and Planning. Mr. Grant was formerly the Vice President and Treasurer.

(4) In November 2016, Morgan C. Stoll was named Vice President and Chief Information Officer.

(5) In November 2016, Martha B. Pritz was named Treasurer.

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 it electronically files or furnishes 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 a part of, or incorporated by reference into, any report or other filing 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. Additional risks and uncertainties that are not currently known to TEP or that are not currently believed by TEP to be material may also harm TEP's business and financial results.

REVENUES

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

Economic conditions in TEP’s service area have a significant impact on customer growth, use per customer and overall sales levels. As a result of weak economic conditions, TEP’s average retail customer base grew by less than 1% in each year from 2012 through 2016. Additionally, economic conditions contributed to a declining average use per customer and lower overall sales over this same period.

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

Research and development activities are ongoing for new technologies that produce power and reduce power consumption. These technologies include renewable energy, customer-sited DG, appliances, equipment, battery storage and control systems. Continued development and use of these technologies and compliance with the ACC's EE Standards and RES 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 Company’s 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, negatively affecting operating revenues, cash flows, and net income by reducing sales.

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

TEP’s ten largest customers represented 11% of total revenues in 2016. TEP sells electricity to mines, military installations, and other large commercial and industrial customers. Retail sales volumes and revenues from these customers could decline as a result of, among other things: global, national, and local economic conditions; curtailments of customer operations due to unfavorable market conditions; military base reorganization or closure decisions by the federal government; the effects of energy efficiency and distributed generation; or the decision by customers to self-generate all or a portion of their energy needs. A reduction in retail kWh sales by any one of TEP’s ten largest 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.

TEP’s Retail Rates consist of base rates and various rate adjustors that are intended to allow for timely recovery of certain costs between rate cases. The ACC is charged with setting Retail Rates at levels that are intended to allow TEP to recover its costs of service and provide it with an opportunity to earn a reasonable rate of return. In setting TEP’s Retail Rates, the ACC could disallow the recovery of costs, not provide for the timely recovery of costs or increase regulatory oversight. If customers or regulators have or develop a negative opinion of the Company's utility services or the electric utility industry in general, this could negatively affect TEP's regulatory outcomes. 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 utility industry and the ways in which this industry is 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.

11

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.

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

The Company is subject to taxation by the various taxing authorities at the federal, state and local levels where it does business. Legislation or regulation could be enacted by any of these governmental authorities which could affect the Company’s tax positions. The Company cannot predict the timing or extent of such tax-related developments which could have a negative impact on TEP's financial results.

ENVIRONMENTAL

TEP is subject to numerous environmental laws and regulations that may increase its cost of operations or expose it to environmental-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 generation facilities and compliance standards related to new and existing generation facilities. These laws and regulations generally require TEP 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, 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 a negative effect on TEP's results of operations, particularly if those costs are not fully recoverable from TEP customers. TEP’s obligation to comply with the EPA’s Regional Haze Rule requirements as a participant or owner in the Springerville, San Juan, Four Corners, and Navajo, coupled with the financial impact of future climate change legislation, other environmental regulations and other business considerations, could jeopardize the economic viability of these generation faculties. Additionally, these regulations may jeopardize continued generation facility operations or the ability of individual participants to meet their obligations and willingness to continue their participation in these facilities potentially resulting in increased operational cost for the remaining participants. 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 generation facilities in which it has a minority interest and is obligated to pay similar costs at the mines that supply these generation facilities. 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.

Federal regulations limiting greenhouse gas emissions require a shift in generation from coal to natural gas and renewable generation and could increase TEP's cost of operations.

In 2015, the EPA issued the Clean Power Plan (CPP) limiting CO_2 emissions from existing and new fossil fueled generation facilities. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan requires CO_2 emission reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. In its current form, the CPP requires a shift in generation from coal to natural gas and renewables and could lead to the early retirement of coal-fired generation in Arizona and New Mexico within the 2022 to 2030 compliance time-frame. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop compliance strategies. TEP is unable to determine whether the current CPP will remain in effect or be modified or any final CPP rule will impact its facilities until all legal challenges have been resolved and the currently required state compliance plans are developed and approved by the EPA.

12

FINANCIAL

Early closure of TEP's coal-fired generation facilities could result in TEP recognizing impairments or increased cost of operations if recovery of TEP's remaining investments in such facilities and the costs associated with early closures were not permitted through rates charged to customers.

TEP's coal-fired generation facilities may be required to be closed before the end of their useful lives in response to economic conditions and/or recent or future changes in environmental regulation, including potential regulation relating to greenhouse gas emissions. If any of the coal-fired generation facilities from which TEP obtains power are closed prior to the end of their useful life, TEP could be required to recognize an 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 generation facilities. Closure of any of such generation facilities 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. As of December 31, 2016, approximately 52% of TEP's generation facilities are coal-fired generation.

Volatility or disruptions in the financial markets, rising interest rates, or unanticipated financing needs, could: increase TEP's financing costs; limit access to the credit markets; affect the Company's ability to comply with financial covenants in debt agreements; and increase TEP's pension funding obligations. Such outcomes may negatively affect liquidity and TEP's ability to carry out the Company's 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 flows 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 negatively 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 reasonable rates, or if our borrowing costs dramatically increase, our ability to finance our operations, meet our debt obligations, and execute our financial strategy could be negatively affected.

Increases in short-term interest rates would increase the cost of borrowing on TEP's tax-exempt variable rate debt obligations of $137 million as of December 31, 2016, and increase the cost of borrowings under its credit facility. In addition, changing market conditions could negatively affect the market value of assets held in our pension and other postretirement plans and may increase the amount and accelerate the timing of required future funding contributions.

Generation facility closings or changes in power flows into TEP's service territory could require us to redeem or defease some or all of the tax-exempt bonds issued for the Company's 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, 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 power within TEP’s two-county retail service area.

As of December 31, 2016, there were outstanding approximately $309 million aggregate principal amount of tax-exempt bonds that financed pollution control expenditures at TEP’s generation facilities. Should certain of TEP’s generation facilities 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 pollution control expenditures would be subject to mandatory early redemption by TEP. Of the total amount outstanding, $37 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $272 million principal amount of the bonds have early redemption dates or final maturities ranging from 2019 to 2022.

In addition, as of December 31, 2016, there were outstanding approximately $307 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 power in TEP’s local service area, it is possible that TEP would no longer qualify as a local furnisher of power within the meaning of the Internal Revenue Code. If TEP could no longer qualify as a local furnisher of power, all of TEP's tax-exempt local furnishing bonds could be subject to mandatory early redemption by TEP or defeasance to the earliest possible redemption date, and TEP could be required to pay additional amounts if interest on such bonds were no longer tax-exempt. Of the total tax-exempt local furnishing bonds outstanding, $100 million of the principal amount of the bonds can currently be redeemed at par upon notice to holders, and $207 million principal amount of the bonds have early redemption dates ranging from 2020 to 2023.

OPERATIONAL

The operation of electric generation facilities and transmission and distribution systems involves risks and uncertainties that could result in reduced generation capability or unplanned outages that could negatively affect TEP’s results of operations, net income, and cash flows.

The operation of electric generation facilities and transmission and distribution systems involves certain risks and uncertainties, including equipment breakdown or failures, fires, weather, 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 failures or other complications, occur from time to time. They are an inherent risk of our business and can cause damage to our reputation. If TEP’s generation facilities and transmission and distribution systems operate below expectations, TEP’s operating results could be negatively affected and/or TEP's capital spending could be increased.

TEP receives power from certain generation 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 negatively affect TEP’s results of operations, net income, and cash flows.

Certain of the generation facilities 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 generation facilities. Further, TEP may have no ability or a limited ability to make determinations on how best to manage the changing economic conditions or environmental requirements which may affect such facilities. A divergence in the interests of TEP and the co-owners or operators, as applicable, of such facilities could negatively impact the business and operations of TEP.

TEP may be subject to physical attacks which could have a negative impact on the Company's business and results of operations.

As operators of critical energy infrastructure, TEP may face a heightened risk of physical attacks on the Company's electric systems. Our electric generation, transmission, and distribution assets and systems are geographically dispersed and are often in rural or unpopulated areas which makes it 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 TEP's business and results of operations.

TEP may be subject to cyber attacks which could have a negative impact on the Company's business and results of operations.

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

If, despite TEP's security measures, a significant cyber or data breach occurred, the Company 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 TEP's 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 generation facilities 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. See Part I, Item 1. Business, Overview of Business of this Form 10-K for additional information regarding the transmission facilities.

TEP's generation facilities (except as noted below), administrative headquarters, warehouses and service centers are located on land owned by TEP. The 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-of-way which generally are subject to termination;
- under or over private property as a result of easements obtained primarily from the record holder of title; or
- over tribal lands under grant of easement by the Secretary of the Interior or lease by Indian Nations.

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 term patent with the State of Arizona. TEP, under separate sale and leaseback arrangements, leases a 50% undivided interest in the Springerville Common Facilities (which do not include land).

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 generation facilities, the transmission lines, and a water diversion facility located on land owned by the Navajo Nation. TEP has also acquired easements for transmission facilities related to San Juan, Four Corners, and Navajo located on Indian Country of the Zuni, Navajo, and Tohono O’odham Nations. 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 and UNS Electric, Inc. (UNS Electric), an affiliate subsidiary of TEP, own a 75% and 25%, respectively, undivided interest in Gila River Unit 3. Gila River Unit 3 is situated on land owned by TEP and UNS Electric, who also own a 25% undivided ownership interest in the common facilities at Gila River as tenants in common. TEP and UNS Electric, together with the remaining 75% common owners have free and clear title of all common facilities.

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 Indian Nations;
- possible inability of TEP to legally enforce its rights against adverse claimants and the Indian Nations without Congressional consent; or
- failure or inability of the 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.

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

- the Solar Zone located at the University of Arizona Technology Park in Pima County, Arizona; and
- the Bright Tucson Community Solar located in Pima County, Arizona.

In addition, TEP has a 30-year easement agreement related to a PV facility in Cochise County, Arizona. The easement is to facilitate the operations of a solar PV renewable energy generation system on behalf of the Department of the Army.

See Part I, Item 1. Business, Overview of Business of this Form 10-K for additional information regarding generation facilities.

ITEM 3. LEGAL PROCEEDINGS

TEP is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company believes such normal and routine litigation will not have a material impact on its consolidated financial results. TEP is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties, and other costs in substantial amounts on TEP.

See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

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

Market Information

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

Dividends

TEP declared and paid dividends to UNS Energy of $50 million in 2016 and 2015 and $40 million in 2014.
See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources and Note 5 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on regulatory restrictions that limit TEP's ability to pay dividends.

ITEM 6. SELECTED FINANCIAL DATA

The following table provides selected financial data for the years 2012 through 2016.

(in thousands)	2016	2015	2014	2013	2012
Income Statement Data					
Operating Revenues	$1,234,995	$1,306,544	$1,269,901	$1,196,690	$1,161,660
Net Income	124,438	127,794	102,338	101,342	65,470
Balance Sheet Data					
Total Utility Plant, Net	$3,782,806	$3,558,229	$3,425,190	$2,944,455	$2,750,421
Total Assets	4,449,989	4,249,478	4,119,830	3,482,860	3,413,638
Long-Term Debt, Net	1,453,072	1,451,720	1,361,828	1,213,367	1,213,246
Non-Current Capital Lease Obligations	39,267	55,324	69,438	131,370	262,138
Other Data					
Ratio of Earnings to Fixed Charges [1]	3.69	3.74	2.56	2.67	2.10

(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 Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information.

17

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 2016 compared with 2015, and 2015 compared with 2014;
- factors affecting our results of operations and outlook;
- liquidity and capital resources including capital expenditures, contractual obligations, and environmental matters;
- critical accounting policies and estimates; and
- recent accounting pronouncements.

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

Management's Discussion and Analysis should be read in conjunction with Part 2, Item 6, Selected Financial Data and the Consolidated Financial Statements and Notes in Part II, 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 Part I, Item 1A. Risk Factors for additional information.

References in this discussion and analysis to "we" and "our" are to TEP.

OUTLOOK AND STRATEGIES

TEP's financial prospects and outlook are affected by many factors including: global, 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:

- Achieving constructive outcomes in our regulatory proceedings that provide us: (i) recovery of our full cost of service and an opportunity to earn an appropriate return on our rate base investments; (ii) updated rates that provide more accurate price signals and a more equitable allocation of costs to our customers; and (iii) the ability to continue providing safe and reliable service.
- Continuing to focus on our long-term resource diversification 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, leveraging and improving our existing utility infrastructure, and maintaining financial strength. This long-term strategy includes a target of meeting 30% of our customers' energy needs with non-carbon emitting resources by 2030.
- Focusing on our core utility business through operational excellence, promoting economic development in our service territory, investing in infrastructure to ensure reliable service, and maintaining a strong community presence.

Operational and Financial Highlights

Management's Discussion and Analysis includes the following notable items:

- In February 2016, TEP entered into an agreement with the Third-Party Owners for the settlement and release of asserted claims and the purchase by TEP of the Third-Party Owners' 50.5% undivided interest in Springerville Unit 1 for $85 million. In September 2016, the purchase was completed and all asserted claims were dismissed. The Third-Party Owners paid TEP $12.5 million for previously unreimbursed operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners.

- In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source as a better-than-BART alternative at Sundt.
- In 2016, TEP recorded $22 million in time value refunds as a result of FERC orders relating to late filed TSAs. TEP paid a total of $17 million in 2016 in time value refunds to the counterparties to these TSAs. In January 2017, TEP and one of the TSA counterparties entered into a settlement agreement resulting in the counterparty paying TEP $8 million and TEP dismissing an appeal previously filed in June 2016.
- In December 2016, TEP notified the owner participant and the lessor of the lease at the Springerville Common Facilities expiring in December 2017 that TEP had elected to purchase its undivided ownership interest in the facilities at the fixed purchase price of $38 million upon the expiration of the lease term.
- In February 2017, the ACC issued a decision in TEP’s rate case approving a non-fuel base rate increase of $81.5 million and a 7.04% return on original cost rate base. The new rates will be effective on or before March 1, 2017.

RESULTS OF OPERATIONS

The following discussion provides the significant items that affected TEP's results of operations in years ended December 31, 2016, 2015, and 2014, presented on an after-tax basis.

2016 compared with 2015

TEP reported net income of $124 million in 2016 compared with $128 million in 2015. The decrease of $4 million, or 3%, was primarily due to:

- $13 million in refunds associated with late-filed TSAs. See Note 7 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-K;
- $6 million in higher depreciation and amortization expense related primarily to an increase in asset base; and
- $4 million in higher operations and maintenance expense resulting primarily from an increase in outside services and employee wages and benefits.

The decrease was partially offset by:

- $8 million in higher revenues related to the Springerville Unit 1 settlement. For further information related to the settlement. See Note 7 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-K;
- $6 million in higher net income as a result of a reduction in the valuation allowance for deferred tax assets based on an increase in projected taxable income; and
- $4 million from higher LFCR revenues that partially offset lower retail sales.

2015 compared with 2014

TEP reported net income of $128 million in 2015 compared with $102 million in 2014. The increase of $26 million, or 25%, was primarily due to:

- $16 million in lower operations and maintenance expense resulting primarily from Fortis acquisition-related costs and planned generation outages at Springerville Units 1 and 2 that occurred in 2014, partially offset by higher operations and maintenance expense related to Gila River Unit 3, labor costs, and outside services;
- $6 million in higher transmission revenues resulting primarily from an increase in sales volumes on favorably priced contracts; and
- $4 million in lower interest expense primarily due to a reduction in the balance of capital lease obligations.

Retail Sales and Revenues

Retail Revenues were $990 million in 2016, $1,022 million in 2015, and $970 million in 2014. Retail Margin Revenues (non-GAAP) were $631 million in 2016, $629 million in 2015, and $626 million in 2014. The table below provides a summary of retail kWh sales, a reconciliation of Retail Margin Revenues to Retail Revenues, and weather data:

	Years Ended December 31,		Increase (Decrease)	Year Ended December 31	Increase (Decrease)
	2016	2015	Percent	2014	Percent
Retail Sales by Customer Class (kWh in millions)					
Residential	3,724	3,724	— %	3,727	(0.1)%
Commercial	2,139	2,124	0.7 %	2,170	(2.1)%
Industrial	2,006	2,063	(2.8)%	2,098	(1.7)%
Mining	997	1,109	(10.1)%	1,137	(2.5)%
Public Authorities	30	33	(9.1)%	33	— %
Total Retail Sales by Class	8,896	9,053	(1.7)%	9,165	(1.2)%
Retail Revenues (in millions)					
Residential	$281	$281	— %	$ 280	0.4 %
Commercial	186	185	0.5 %	188	(1.6)%
Industrial	102	103	(1.0)%	104	(1.0)%
Mining	35	38	(7.9)%	38	— %
Public Authorities	2	2	— %	2	— %
Retail Margin Revenues by Class	606	609	(0.5)%	612	(0.5)%
LFCR Revenues	18	12	50.0 %	11	9.1 %
DSM Performance Bonus	2	3	(33.3)%	2	50.0 %
Other Retail Margin Revenues	5	5	— %	1	*
Retail Margin Revenues (non-GAAP) (1)	631	629	0.3 %	626	0.5 %
Fuel and Purchased Power Revenues	305	344	(11.3)%	303	13.5 %
DSM and RES Surcharge Revenues	54	49	10.2 %	41	19.5 %
Total Retail Revenues (GAAP)	$990	$1,022	(3.1)%	$ 970	5.4 %
Average Retail Margin Rate by Class (cents / kWh)					
Residential	7.55	7.55	— %	7.51	0.5 %
Commercial	8.70	8.71	(0.1)%	8.66	0.6 %
Industrial	5.08	4.99	1.8 %	4.96	0.6 %
Mining	3.51	3.43	2.3 %	3.34	2.7 %
Public Authorities (2)	5.68	5.61	1.2 %	6.06	(7.4)%
Average Retail Margin Rate by Class	6.81	6.73	1.2 %	6.68	0.7 %
Total Average Retail Margin Rate (3)	7.09	6.95	2.0 %	6.80	2.2 %
Average Fuel and Purchased Power Rate	3.43	3.80	(9.7)%	3.31	14.8 %
Average DSM and RES Surcharge Rate	0.61	0.54	13.0 %	0.48	12.5 %
Total Average Retail Rate	11.13	11.29	(1.4)%	10.59	6.6 %
Weather Data					
Cooling Degree Days					
Actual	1,515	1,576	(3.9)%	1,557	1.2 %
10-Year Average	1,535	1,520	*	1,515	*
Heating Degree Days					
Actual	992	1,072	(7.5)%	930	15.3 %
10-Year Average	1,286	1,317	*	1,335	*

* Not meaningful

(1) Retail Margin Revenues, a non-GAAP financial measure, should not be considered as an alternative to 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 for investors and analysts because it demonstrates the underlying revenue trend and performance of our core utility business. Retail Margin Revenues represents the portion of retail operating revenues from kWh sales, LFCR Revenues, DSM Performance Bonus, and certain Other Retail Margin Revenues available to cover the non-fuel operating expenses of our core utility business.

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

(3) Total Average Retail Margin Rate includes revenue related to LFCR Revenues, DSM Performance Bonus, and Other Retail Margin Revenues included in Retail Margin Revenues.

Retail Revenues were lower in 2016 compared with 2015 primarily due to a decrease in the PPFAC rate partially offset by higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to an increase in LFCR revenues.

Retail Revenues were higher in 2015 compared with 2014 primarily due to an increase in the PPFAC rate and higher Retail Margin Revenues. Retail Margin Revenues were higher primarily due to higher LFCR Revenues, DSM Performance Bonus, and Other Retail Margin Revenues related to adjustor mechanisms.

Wholesale Revenues

	Years Ended December 31,		
(in millions)	2016	2015	2014
Long-Term Wholesale	$27	$36	$28
Short-Term Wholesale	81	104	114
Transmission	31	27	16
Transmission Refunds [1]	(22)	—	—
Total Wholesale Revenues	$117	$167	$158

(1) FERC ordered TEP to make refunds associated with various late-filed TSAs for the time period during which rates were charged without FERC authorization. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information on the FERC ordered refunds.

Wholesale Revenues decreased by $50 million, or 30%, in 2016 compared with 2015 primarily due to refunds related to the late-filed TSAs and decreased volumes and market prices of both short-term and long-term wholesale sales resulting from unfavorable market conditions and termination of a firm contract at the end of May 2016.

Wholesale Revenues increased by $9 million, or 6%, in 2015 compared with 2014 primarily due to a new long-term transmission agreement with UNS Electric related to Gila River Unit 3, transmission contract renewals resulting in favorable pricing, and new long-term wholesale agreements, partially offset by a decrease in market prices of short-term sales resulting from unfavorable market conditions.

Short-Term Wholesale Revenues are primarily related to the ACC jurisdictional assets and are returned to retail customers by crediting the revenues against fuel and purchased power costs eligible for recovery through the PPFAC.

Other Revenues

	Years Ended December 31,		
(in millions)	2016	2015	2014
Springerville Units 3 and 4 [1]	$86	$91	$112
Other	42	27	29
Total Other Revenues	$128	$118	$141

(1) Represents revenues and reimbursements to TEP from Tri-State Generation and Transmission Association, Inc. (Tri-State), the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, related to the operation of these generation facilities.

Other Revenues includes: (i) reimbursements related to Springerville Units 3 and 4; (ii) inter-company revenues from TEP's affiliates, UNS Gas, Inc. (UNS Gas), an affiliated subsidiary of TEP, and UNS Electric, for corporate services provided by TEP; and (iii) miscellaneous service-related revenues such as rent on power pole attachments, damage claims, and customer late fees.

Other Revenues increased by $10 million, or 8%, in 2016 compared with 2015 primarily due to the Springerville Unit 1 settlement agreement. For further information related to the Springerville Unit 1 settlement. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K. The increase was offset by a decrease in reimbursed costs in 2016 for Springerville Units 3 and 4 related to planned generation outages in 2015.

Other Revenues decreased by $23 million, or 16%, in 2015 compared with 2014 primarily due to a decrease in reimbursed costs in 2015 for Springerville Units 3 and 4 related to planned generation outages in 2014.

Operating Expenses

Generation Output and Fuel and Purchased Power Expense

TEP's fuel and purchased power expense and energy resources are detailed below:

	Generation and Purchased Power (kWh)			Fuel and Purchased Power Expense		
	Years Ended December 31,					
(in millions)	2016	2015	2014	2016	2015	2014
Coal-Fired Generation	8,310	8,584	9,271	$ 192	$ 209	$ 232
Gas-Fired Generation	3,283	2,723	1,210	93	91	60
Utility Owned Renewable Generation	68	65	48	—	—	—
Reimbursed Fuel Expense, Springerville Units 3 and 4 (1)	—	—	—	5	5	5
Total Generation	11,661	11,372	10,529	290	305	297
Purchased Power, Non-Renewable	1,126	2,627	2,895	39	81	121
Purchased Power, Renewable	666	452	300	46	44	32
Total Purchased Power	1,792	3,079	3,195	85	125	153
Transmission and Other PPFAC Recoverable Costs	—	—	—	24	25	18
Increase (Decrease) to Reflect PPFAC Recovery Treatment	—	—	—	21	40	(11)
Total Generation and Purchased Power	13,453	14,451	13,724	$ 420	$ 495	$ 457
Less Line Losses and Company Use	(786)	(719)	(859)			
Total Power Sold	12,667	13,732	12,865			

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

Fuel and Purchased Power Expense decreased by $75 million, or 15%, in 2016 compared with 2015 primarily due to a decrease in non-renewable purchased power volumes, Coal-Fired Generation kWhs, and fuel costs per kWhs (see table below). The decrease was partially offset by an increase in Gas-Fired Generation kWhs.

Fuel and Purchased Power Expense increased by $38 million, or 8%, in 2015 compared with 2014 primarily due to an increase in the PPFAC charge and additional generation and transmission costs associated with Gila River Unit 3. The increase was partially offset by a decrease in fuel and purchased power costs per kWhs (see table below) and decreased coal-fired generation at Springerville Unit 1 as a result of the lease expiration in January 2015.

The table below summarizes average fuel cost of generated and purchased kWh:

	Years Ended December 31,		
(cents per kWh)	2016	2015	2014
Coal	2.30	2.44	2.50
Gas	2.84	3.35	4.99
Purchased Power, Non-Renewable	3.43	3.04	4.14
Purchased Power, Renewable	7.00	9.82	10.50
All Resources	3.15	3.31	3.64

Operations and Maintenance Expense

The table below summarizes the items included in Operations and Maintenance Expense:

	Years Ended December 31,		
(in millions)	2016	2015	2014
Reimbursed Expenses, Springerville Units 3 and 4 [1]	$61	$65	$84
Reimbursed Expenses, Customer Funded Renewable Energy and DSM Programs [2]	31	25	23
Other [3]	262	255	272
Total Operations and Maintenance Expense	$354	$345	$379

(1) Expenses related to Springerville Units 3 and 4 are reimbursed with corresponding amounts recorded in Other Revenue.

(2) These expenses are collected from customers and the corresponding amounts are recorded in Retail Revenue.

(3) Includes the Third-Party Owners' share of expenses related to Springerville Unit 1 for years ended 2015 and 2014 and part of 2016.

Operations and Maintenance Expense increased by $9 million, or 3%, in 2016 compared with 2015 primarily due to an increase in expenses related to planned generation outages, outside services, and employee wages and benefits and an increase in RES and DSM program expenses.

Operations and Maintenance Expense decreased by $34 million, or 9%, in 2015 compared with 2014 primarily due to a decrease in Springerville Units 3 and 4 expenses, related to outages that incurred in 2014 as well as Fortis acquisition-related costs and outages at Springerville Units 1 and 2 that occurred in 2014. The decrease was partially offset by higher operations and maintenance expenses related to Gila River Unit 3, labor costs, and outside services.

FACTORS AFFECTING RESULTS OF OPERATIONS

2017 RATE ORDER

In February 2017, the ACC issued a rate order in the rate case filed by TEP in November 2015. TEP's rate filing was based on a test year ended June 30, 2015. The 2017 Rate Order approved new rates to be effective on or before March 1, 2017.

The provisions of the 2017 Rate Order include, but are not limited to:

- a non-fuel base rate increase of $81.5 million which includes $15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016;
- a 7.04% return on original cost rate base of approximately $2 billion;
- a cost of equity component of 9.75% and a cost of debt component of 4.32%;
- a capital structure for rate making purposes of approximately 50% common equity and 50% long-term debt;
- adoption of TEP's proposed depreciation and amortization rates, which include a reduction in the depreciable life for San Juan Unit 1; and
- a request to apply excess depreciation reserves against the unrecovered net book value (NBV) of San Juan Unit 2 and the coal handling facilities at Sundt due to early retirement.

The ACC deferred TEP's proposed changes to net metering and rate design for new DG customers to Phase 2, which is expected to begin in the second quarter of 2017. TEP cannot predict the outcome of this proceeding.

Generation Resources

As of December 31, 2016, approximately 52% of TEP's generation capacity is coal-fired generation. TEP is evaluating additional steps to reduce its reliance on coal-fired generation.

Integrated Resource Plan

In March 2016, as required by the ACC, TEP filed its 2016 Preliminary Integrated Resource Plan (IRP). A Supplement to the Preliminary IRP was filed on September 30, 2016, with the final 2017 IRP to be filed by April 2017. TEP's Preliminary IRP and Supplement disclose TEP's plan to reduce its overall coal capacity by 170 MW at San Juan in 2017, and outlines options for further reductions at San Juan in 2022, Navajo in 2030, and Four Corners in 2031. TEP’s final IRP will address the long-term viability of Navajo. TEP's existing generation fleet faces a number of uncertainties impacting the viability of continued operations including competition from other resources, fuel contract extensions, environmental regulations and the ability of existing owners to continue their participation. Given this uncertainty, TEP may consider options that include changes in generation facility ownership shares, unit shutdowns, or sale of generation assets to third-parties. TEP plans to seek regulatory recovery for amounts that would not otherwise be recovered if and when any assets are retired.

See Part I, Item 1. Business, Environmental Matters of this Form 10-K for additional information regarding the impact of environmental matters on generation facility operations and Business, Overview of Business for additional information regarding TEP's generation facilities.

Navajo Generating Station

Navajo is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. In February 2017, SRP, the operator of Navajo announced that they do not currently intend to operate Navajo past the current term of the lease. TEP supports continued operation of the plant through December 2019 if a lease extension can be reached with the Navajo Nation. Without a lease extension, the owners would be forced to cease operations at Navajo this year to allow enough time for decommissioning to be completed before the current lease expires. As of December 31, 2016, TEP's NBV of Navajo was $40 million. Upon the retirement of Navajo, TEP will seek rate recovery of any unrecovered costs. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Springerville Common Facilities Purchase Commitment

The Springerville Common Facilities leases have an initial term ending December 2017 for one lease and January 2021 for the other two leases.

In December 2016, TEP notified the owner participant and the lessor of the lease that expires in December 2017 that TEP had elected to purchase a 17.8% undivided ownership interest in the Springerville Common Facilities at the fixed purchase price of $38 million upon the expiration of the lease. Due to TEP's purchase commitment, in December 2016, TEP recorded an increase of $36 million to Current Obligations Under Capital Leases and Utility Plant Under Capital Lease, which represents the present value of the total purchase commitment, on the Consolidated Balance Sheets.

Under the remaining two leases, TEP has options to: (i) renew the leases for periods of two or more years; or (ii) exercise the purchase options under these leases.

See Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Springerville Coal Handling Facilities Lease Purchase

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

Tri-State, the lessee of Springerville Unit 3, is obligated to either: (i) buy a 17.05% undivided interest in the facilities for approximately $24 million; or (ii) continue to make payments to TEP for the use of the facilities. In March 2016, Tri-State notified TEP that it was exercising its option to purchase the undivided interest in the facilities. As of December 31, 2015, the 17.05% undivided interest in the Springerville Coal Handling Facilities was classified as Assets Held for Sale, Net. However, as of December 31, 2016, TEP's management no longer believed the sale would be completed. As a result, in December 2016 Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities was reclassified as Utility Plant from Assets Held for Sale, Net on the Consolidated Balance Sheets. In 2016, TEP recorded $1 million of catch-up depreciation for the period of time the facilities were recorded in Assets Held for Sale, Net. In 2016, TEP was reimbursed $4 million per year in operations costs by Tri-State related to its portion of the Springerville Coal Handling Facilities.

Sales to Mining Customers

TEP's largest mining customer took steps to reduce operational expenses by curtailing production in 2016 due to a decline in commodity prices. As a result, retail sales to mining customers declined by 10% in 2016 compared with the same period in 2015. While TEP cannot predict how long commodity prices will remain low or the total impact the prices will have on mining production in the future, any future curtailment of mining production could negatively impact retail sales to mining customers. As of December 31, 2016, mining customers accounted for 11% of TEP's total retail sales and 6% of Retail Revenues.

Interest Rates

See Part II, Item 7A. Quantitative and Qualitative Disclosures about Market Risk of this Form 10-K for information regarding interest rate risks and its impact on earnings.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

Cash flows may vary during the year with cash flows from operations typically the lowest in the first quarter of the year and highest in the third quarter due to TEP's summer peaking load. As a result of the varied seasonal cash flow, we will use, as needed, our revolving credit facility to assist in funding business activities. We believe that we have sufficient liquidity under our revolving credit facility to meet short-term working capital needs and to provide credit enhancement as necessary under energy procurement and hedging agreements. The availability and terms under which TEP has access to external financing depends on a variety of factors, including its credit ratings and conditions in the overall capital markets.

Available Liquidity

(in millions)	December 31, 2016
Cash and Cash Equivalents	$ 36
Amount Available under Revolving Credit Facility (1)	250
Total Liquidity	$ 286

(1) TEP's revolving credit facility provides for $250 million of revolving credit commitments with a Letter of Credit (LOC) sublimit of $50 million through its original maturity date of October 2020. In October 2016, TEP extended the agreement one year to October 2021. The credit facility commitments will be reduced to $217.5 million in the final year of the agreement.

Future Liquidity Requirements

We expect to meet all of our financial obligations and other anticipated cash outflows for the foreseeable future. These obligations and anticipated cash outflows include, but are not limited to, dividend payments, debt maturities, and obligations included in the Contractual Obligations and forecasted Capital Expenditures tables below.

See Part III, Item 7A. Quantitative and Qualitative Disclosures about Market Risk for additional information regarding TEP's market risks and Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding TEP's financing arrangements.

Summary of Cash Flows

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

	Years Ended		Increase (Decrease)	Year Ended	Increase (Decrease)
(in millions)	2016	2015	Percent	2014	Percent
Operating Activities	$425	$365	16.4 %	$314	16.2 %
Investing Activities	(376)	(503)	(25.2)%	(518)	(2.9)%
Financing Activities	(69)	120	(157.5)%	253	(52.6)%
Net Increase (Decrease) in Cash	(20)	(18)	(11.1)%	49	(136.7)%
Cash and Cash Equivalents, Beginning of Year	56	74	(24.3)%	25	196.0 %
Cash and Cash Equivalents, End of Year	$36	$56	(35.7)%	$74	(24.3)%

Cash flows in 2016 reflect a reduction in capital expenditures compared with prior years and no new long-term debt or revolving credit agreement borrowings. Cash flows in both 2015 and 2014 included large capital expenditures. These capital requirements were met with a combination of equity contributions from UNS Energy and long-term borrowings as discussed in Financing Activities below.

25

In 2015, we issued long-term debt and used the proceeds to repay revolving and term loans under our credit agreements and pay a portion of the purchase price for interests in the Springerville Coal Handling Facilities. In addition, we received an equity contribution from UNS Energy and used the proceeds to repay the outstanding balances under our revolving credit facilities and redeem long-term variable rate tax-exempt bonds which were called for redemption in June 2015.

In 2014, we received an equity contribution from UNS Energy and used the proceeds to pay for the purchase of both Gila River Unit 3 and Springerville Unit 1 leased assets.

Operating Activities

2016 compared with 2015

In 2016, net cash flows from operating activities increased by $60 million compared with 2015 primarily due to a:

- $20 million temporary over-recovery of fuel and purchased power costs under the PPFAC mechanism;
- $17 million decrease in cash paid for pension and other postretirement benefits funding;
- $12.5 million increase in cash proceeds related to the settlement of operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners; and
- $28 million increase attributable to timing differences in Accrued Payable and Accrued Charges.

The increase in net cash flows from operating activities was partially offset by an increase of $11 million in cash paid for incentive compensation in 2016 compared with the same period in 2015 in which no incentive compensation was paid. As a result of the Fortis acquisition in 2014, payments under the annual incentive compensation plan were accelerated to the third quarter of 2014 from the first quarter of 2015.

2015 compared with 2014

In 2015, net cash flows from operating activities increased by $51 million compared with 2014 primarily due to a:

- $39 million increase in cash proceeds from retail and wholesale sales, net of fuel and purchased power costs paid, driven primarily by an increase in the average PPFAC rate; and
- $34 million decrease in cash paid for acquisition-related costs and incentive compensation primarily due to the 2014 acquisition.

The increase in net cash flows from operating activities was partially offset by $16 million of higher cash paid to fund pension and other postretirement plans.

Investing Activities

2016 compared with 2015

In 2016, net cash flows used for investing activities decreased by $127 million compared with 2015 primarily due to a:

- $120 million purchase in April 2015 of an additional 86.7% undivided ownership interest in the Springerville Coal Handling Facilities increasing its total ownership interest to 100%; and
- $83 million decrease in cash paid in 2016 for capital expenditures primarily due to construction cost in 2015 of a new 500kV transmission line.

The decrease in net cash flows used for investing activities was partially offset by a:

- $85 million purchase in September 2016 of a 50.5% undivided ownership interest in Springerville Unit 1 compared to a $46 million purchase in January 2015 of a 24.8% undivided ownership interest in the same generation facility;
- $24 million in cash proceeds in May 2015 from the sale of a 17.05% undivided ownership interest in Springerville Coal Handling Facilities to SRP; and
- $12 million increase in cash paid in 2016 for the purchase of renewable energy credits.

2015 compared with 2014

In 2015, net cash flows used for investing activities decreased by $15 million compared with 2014 primarily due to a:

- $164 million purchase in December 2014 of a 75% undivided ownership interest in Gila River Unit 3; and
- $20 million purchase in December 2014 of a 10.6% interest in Springerville Unit 1.

The decrease in net cash flows used for investing activities was partially offset by a:

- $96 million net purchase in 2015 of the Springerville Coal Handling Facilities consisting of the $120 million purchase of an additional 86.7% undivided ownership interest, partially offset by a $24 million sale of the 17.05% undivided ownership interest to SRP;
- $46 million purchase in January 2015 of an additional 24.8% undivided ownership interest in Springerville Unit 1 increasing our total ownership interest to 49.5%;
- $11 million decrease in cash receipts for contributions in aid of construction received; and
- $10 million increase in capital expenditures to fund system reinforcement through replacements and betterments.

Financing Activities

2016 compared with 2015

In 2016, net cash flows from financing activities decreased by $189 million compared with 2015 primarily due to a:

- $299 million decrease in cash proceeds in 2016 for the issuance of long-term debt in February 2015; and
- $180 million decrease in cash proceeds in 2016 from a UNS Energy equity contribution in June 2015.

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

- $209 million decrease in cash paid in 2016 for the purchase of $130 million in tax-exempt long-term debt in January 2015, and the retirement of $79 million in long-term debt in August 2015; and
- $85 million decrease in cash paid in 2016, net of proceeds borrowed, under TEP's revolving credit facilities.

2015 compared with 2014

In 2015, net cash flows from financing activities decreased by $133 million compared with 2014 primarily due to:

- $209 million increase in cash paid to purchase of $130 million in fixed rate tax-exempt long-term debt in January 2015, and the retirement of $79 million in variable rate tax-exempt bonds in August 2015;
- $170 million decrease in cash proceeds borrowed and higher repayments under TEP's revolving credit facilities;
- $45 million decrease in cash proceeds from UNS Energy's equity contributions; and
- $10 million increase in cash paid for dividend payments.

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

- $152 million decrease in cash payments due to the expiration of capital lease obligations in 2015; and
- $150 million increase in cash proceeds from the issuance of long-term debt, in February 2015.

External Sources of Liquidity

Short-Term Investments

TEP’s short-term investment policy governs the investment of excess cash balances. We periodically review and update this policy in response to market conditions. As of December 31, 2016, TEP's short-term investments included highly-rated and liquid money market funds.

Access to Revolving Credit Facility

We have access to working capital through a revolving credit agreement with lenders. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. As of December 31, 2016, no amounts were drawn under the revolving credit facility.

For details on TEP's credit facility see Note 6 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Debt Financing

We use debt financing to meet a portion of our capital needs and lower our overall cost of capital. We are exposed to adverse changes in interest rates to the extent that we rely on variable rate financing. TEP's cost of capital is also affected by our credit ratings.

In January 2016, the ACC issued an order granting TEP financing authority. The order extends and expands the previous financing authority by: (i) extending authority from December 2016 to December 2020; (ii) increasing the outstanding long-term debt limitation from $1.7 billion to $2.2 billion; (iii) allowing parent equity contributions of up to $400 million; and (iv) continuing the interest rate hedging authority.

We have no plans to raise additional capital in 2017. TEP has, from time to time, refinanced or repurchased portions of its outstanding debt before scheduled maturity. Depending on market conditions, TEP may refinance other debt issuances or make additional debt repurchases in the future.

Credit Ratings

Credit ratings affect our access to capital markets and supplemental bank financing. As of December 31, 2016, TEP’s credit ratings for senior unsecured debt were A3 from Moody’s and BBB+ from S&P Global Ratings.

TEP's credit ratings are dependent on a number of factors, both quantitative and qualitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell, or hold TEP securities. Each rating should be evaluated independently of any other ratings.

Debt Covenants

Certain of TEP's debt agreements contain pricing based on TEP’s credit ratings. A change in TEP’s credit ratings can cause an increase or decrease in the amount of interest TEP pays on its borrowings, and the amount of fees it pays for its LOCs and unused commitments. Also, under certain agreements, should TEP fail to maintain compliance with covenants, lenders could accelerate the maturity of all amounts outstanding. As of December 31, 2016, TEP was in compliance with these covenants.

TEP conducts its wholesale marketing and risk management activities under certain master agreements. Under these agreements, TEP may be required to post credit enhancements in the form of cash or an LOC due to exposures exceeding unsecured credit limits provided to TEP, changes in contract values, changes in TEP’s credit ratings, or material changes in TEP’s creditworthiness. As of December 31, 2016, TEP had posted no LOCs as credit enhancements with its 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.

Contribution from Parent

TEP received no equity contributions in 2016. UNS Energy made an equity contribution to TEP of $180 million in 2015 and $225 million in 2014. The contributions were used to repay revolving credit loans, redeem bonds, and provide additional liquidity to TEP.

Dividends Paid to Parent

TEP declared and paid $50 million in dividends to UNS Energy in 2016 and 2015 and $40 million in 2014.

The ACC's approval of the acquisition of UNS Energy by Fortis in August 2014 contained a condition restricting TEP's dividend payments to UNS Energy to no more than 60% of TEP's annual net income for the earlier of five years or until such time that TEP's equity capitalization reached 50% as accounted for in accordance with GAAP. In June 2016, TEP reached the equity capitalization threshold.

Capital Expenditures

TEP's routine capital expenditures include funds used for customer growth, system reinforcement, replacements and betterments, and costs to comply with environmental rules and regulations. In 2016, total capital expenditures of $335 million, included the purchase of the remaining ownership interest in Springerville Unit 1. In 2015, total capital expenditures of $500 million, included the purchase of an undivided ownership interest in Springerville Unit 1 and the remaining ownership interest in the Springerville Coal Handling Facilities. In 2014, total capital expenditures of $507 million, included the purchase of an interest in Gila River Unit 3, undivided ownership interests in Springerville Unit 1, and construction costs for a new 500-kilovolt (kV) transmission line in Pinal County that began in December 2014 and concluded in late 2015.

We expect capital requirements to remain stable from 2017 through 2021. TEP's forecasted capital expenditures are summarized below:

(in millions)	2017	2018	2019	2020	2021
Generation Facilities:					
Environmental Compliance	$23	$10	$1	$4	$2
Renewable Energy	—	26	26	26	26
Springerville Common Lease Purchase	38	—	—	—	9
Other Generation Facilities	67	49	60	79	108
Total Generation Facilities	128	85	87	109	145
Transmission and Distribution	151	152	125	142	148
General and Other [(1)]	66	47	106	53	37
Total Capital Expenditures	$345	$284	$318	$304	$330

[(1)] General and Other includes cost for information technology, fleet, facilities, and communication equipment.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to fluctuations in business and market conditions, construction schedules, possible early plant closures, changes in generation resources, environmental requirements, state or federal regulations, and other factors. We expect to pay for forecasted capital expenditures with internally generated funds and external financings, which may include issuances of long-term debt or other borrowings.

Contractual Obligations

The following chart displays TEP's contractual obligations by maturity and by type of obligation as of December 31, 2016:

		Payments Due by Period			
(in millions)	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Long-Term Debt					
Principal [(1)]	$1,466	$—	$ 137	$ 330	$999
Interest [(2)]	709	59	118	111	421
Capital Lease Obligations [(3)]	97	54	24	19	—
Operating Leases: [(4)]					
Land Easements and Rights-of-Way	81	1	2	3	75
Operating Leases Other	9	1	2	2	4
Purchase Obligations:					
Fuel, Including Transportation [(5)]	631	100	152	110	269
Purchased Power	32	32	—	—	—
Transmission	78	18	38	12	10
Renewable Purchase Power Agreements [(6)]	1,048	64	128	126	730
RES Performance-Based Incentives [(7)]	99	8	16	16	59
Acquisition of Springerville Common Facilities [(8)]	68	—	—	68	—
Other Long-Term Liabilities: [(9)] [(10)]					
Restricted and Performance-Based Stock Units	4	—	4	—	—
Pension and Other Postretirement [(11)]	78	16	12	13	37
Total Contractual Obligations	$4,400	$353	$ 633	$ 810	$2,604

(1) $37 million of TEP's variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in 2019 as though the LOC terminates without replacement upon expiration of the 2010 Reimbursement Agreement. TEP's 2013 tax-exempt variable rate Industrial Development Revenue Bonds (IDRB), which have an aggregate principal amount of $100 million and mature in 2032, are subject to mandatory tender for purchase in 2018. Total long-term debt is not reduced by $10 million of related unamortized debt issuance costs or $3 million of unamortized original issue discount.

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

(3) Effective with commercial operation of Springerville Unit 3 in July 2006 and Unit 4 in December 2009, Tri-State and SRP began reimbursing TEP for various operating costs related to the common facilities on an ongoing basis. The common facilities include assets leased by TEP at Springerville. Upon expiration of the Springerville Coal Handling lease in April 2015, TEP purchased the interests in those assets. SRP then purchased an undivided interest in the coal handling assets from TEP. Tri-State and SRP each continue to reimburse TEP for their shares of common assets owned or leased by TEP. TEP was reimbursed for $10 million of operating costs in 2016 by SRP and Tri-State and expects to be reimbursed $10 million of operating costs in 2017. Capital Lease Obligations do not reflect any reduction associated with this reimbursement. Our capital lease obligation balances decline over time as scheduled capital lease payments are made by TEP.

(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 Navajo, San Juan, and Four Corners as the timing of payment has not been determined. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding

TEP's share of reclamation costs.

(6) TEP enters into long-term renewable PPAs which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under these contracts if power is not delivered, the table above includes estimated future payments based on expected power deliveries. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding PPAs.

(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. See Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding PBIs.

(8) The Springerville Common Facilities Leases have an initial term ending December 2017 for one lease and January 2021 for the other two leases, subject to optional renewal periods of two or more years. In December 2016, TEP entered into a commitment to purchase the lease, which has an initial term ending December 2017. TEP may renew the other two leases or exercise its remaining fixed-price purchase options.

(9) Excludes Asset Retirement Obligations (ARO) of $33 million expected to occur through 2066.

(10) Excludes unrecognized tax benefits of $12 million. At this time we are unable to make a reasonably reliable estimate of the timing of payments in individual years in connection with these tax liabilities.

(11) These obligations represent TEP's expected contributions to pension plans in 2017, 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 beyond 2017 are excluded.

Off Balance Sheet Arrangements

Other than the unrecorded contractual obligations in the table above, we do not have any arrangements or relationships with entities that are not consolidated into the financial statements.

Income Tax Position

Prior year tax legislation and the Consolidated Appropriations Act of 2016, include provisions that make qualified property placed in service between 2010 and 2019 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 2016 and does not expect to make any payments until 2020.

Environmental Matters

The EPA regulates the amount of SO_2, NO_x, CO_2, particulate matter, mercury, and other by-products produced by generation facilities. TEP may incur additional costs to comply with future changes in federal and state environmental laws, regulations, and permit requirements at its generation facilities. Environmental laws and regulations are subject to a range of interpretations, which may ultimately be resolved by the courts. Because these laws and regulations continue to evolve, TEP is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. Complying with these changes may reduce operating efficiency. TEP capitalized $40 million in 2016, $33 million in 2015, and $11 million in 2014 in costs incurred to comply with environmental rules and regulations. In addition, we recorded operations and maintenance expenses of $6 million in 2016, 2015, and 2014. TEP expects to recover the cost of environmental compliance through Retail Rates.

Hazardous Air Pollutant Requirements

In February 2012, the EPA issued final rules for the control of mercury emissions and other hazardous air pollutants from generation facilities. Based on the EPA's final Mercury and Air Toxics Standards (MATS) rules, additional emission control equipment would have been required by April 2015. TEP, as operator of Springerville and Sundt, and the operators of Navajo and Four Corners received extensions until April 2016 to comply with the MATS rules. In June 2015, the D.C. Circuit Court of Appeals remanded the MATS rules to the EPA for further consideration. Despite the June 2015 ruling, TEP proceeded with its planned MATS compliance activity at each generation facilities. In March 2016, the installation of mercury control systems was completed at Navajo. TEP's share of the installation costs were approximately $1 million. In addition, TEP completed the installation of mercury control systems on Units 1 and 2 at Springerville in March 2016. TEP's share of the installation costs were approximately $3 million. At this time, all generation facilities TEP operates or is a participant in are in compliance with the MATS rules.

Regional Haze Rules

The EPA's Regional Haze Rules require emission controls known as Best Alternative Retrofit Technology (BART) for certain industrial facilities emitting air pollutants that reduce visibility in national parks and wilderness areas. The rule calls for all states to establish goals and emission reduction strategies for improving visibility. States must submit these goals and strategies to the EPA for approval. Because Navajo and Four Corners are located on land leased from the Navajo Nation, they are not subject to state oversight; the EPA oversees regional haze planning for these generation facilities.

In the western United States, Regional Haze BART determinations have focused on controls for NO_x, often resulting in a requirement to install Selective Catalytic Reduction (SCR). The costs to comply with the BART rule, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of Navajo and Four Corners or for individual owners to continue to participate in these generation facilities. The BART provisions do not apply to Springerville Units 1 and 2 since they were constructed in the 1980s, after the time frame as designated by the rules. Other provisions of the Regional Haze Rules requiring further emission reductions are not likely to impact Springerville operations until after 2021. In December 2016, the EPA signed a final rule, entitled "Protection of Visibility: Amendments to Requirements for State Plans." Among other things, the rule changes the date for submittal of the next Regional Haze implementation plan from 2018 to 2021. Based on recent Regional Haze requirement timeframes, TEP anticipates that impacts, if any, to Springerville will likely occur three to five years after the 2021 plan submittal date. TEP cannot predict the ultimate outcome of these matters.

TEP's estimated NO_x emissions control costs to comply with the rules include the following:

(in millions)	Navajo	Four Corners
Capital Expenditures	$ 47	$ 44
Annual Operations and Maintenance Expenses	2	2
Compliance Year	2030	2018

Navajo

In August 2014, the EPA published a final Federal Implementation Plan (FIP) which provides that one unit at Navajo will be shut down by 2020, SCR (or the equivalent) will be installed on the remaining two units by 2030, and conventional coal-fired generation will cease by December 2044. The final BART rule includes options that accommodate potential ownership changes at the plant. The plant has until December 2019 to notify the EPA of how it will comply with the FIP.

Four Corners

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

San Juan

In October 2014, the EPA published a final rule approving a revised State Implementation Plan (SIP) covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017 and the installation of Selective Non-Catalytic Reduction (SNCR) on Units 1 and 4. TEP owns 50% of Units 1 and 2 at San Juan. PNM, the operator of San Juan, completed the installation of SNCR in February 2016. TEP's share of installation costs were $12 million. PNM obtained New Mexico Public Regulation Commission approval to shut down Units 2 and 3 at San Juan. As of December 31, 2016, the NBV of TEP's share in San Juan Unit 2 was $98 million. TEP will apply excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding the 2017 Rate Order.

Sundt

In June 2014, the EPA issued a final rule that required TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continued 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 was required to notify the EPA of its decision by March 2017. In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source to comply with the better-than-BART alternative emission limits. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

As of December 31, 2016, the NBV of the coal handling facilities at Sundt was $16 million. TEP will apply excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 2 for additional information regarding the 2017 Rate Order.

Greenhouse Gas Regulation

In August 2015, the EPA issued the CPP limiting CO_2 emissions from existing and new fossil fueled generation facilities. The CPP establishes state-level CO_2 emission rates and mass-based goals that apply to fossil fuel-fired generation. The plan targets CO_2 emissions reductions for existing facilities by 2030 and establishes interim goals that begin in 2022. States were required to develop and submit a final compliance plan, or an initial plan with an extension request, to the EPA by September 2016. States that received an extension are required to submit a final completed plan to the EPA by September 2018.

The EPA incorporated the compliance obligations for existing generation facilities located in Indian Country, like the Navajo Nation, in the existing sources rule and a newly proposed Federal Plan using a compliance method similar to that of the states. The proposed Federal Plan would be implemented for any Indian Nation and/or state that does not submit a plan or that does not have an EPA or state approved plan. TEP will work with the participants at Four Corners and Navajo to determine how this revision may impact compliance and operations at both facilities. TEP has submitted comments on the proposed Federal Plan impacting our facilities, including Four Corners and Navajo, stating, among other things, that the EPA should not regulate the greenhouse gases on the Navajo Nation because it is not appropriate or necessary. The reduction of greenhouse gases achieved due to the shutdowns resulting from Regional Haze compliance will be equivalent to those required under the CPP rule.

TEP's compliance requirements under the CPP are subject to the outcomes of potential proceedings and litigation challenging the rule. In February 2016, the U.S. Supreme Court granted a stay effectively ordering the EPA to stop CPP implementation efforts until legal challenges to the regulation have been resolved. The ruling introduces uncertainty as to whether and when the states and utilities will have to comply with the CPP rule. TEP will continue to work with the Arizona Department of Environmental Quality to determine what, if any, actions need to be taken in light of the ruling.

In September 2016, the D.C. Circuit Court of Appeals heard oral arguments on the CPP. A decision is not expected until early 2017. TEP will continue to work with the other Arizona and New Mexico utilities, as well as the appropriate regulatory agencies, to develop the state compliance plans. TEP is unable to determine how the final CPP rule will impact its facilities until state plans are developed and approved by the EPA. TEP cannot predict the ultimate outcome of these matters.

Coal Combustion Residuals Regulation

In April 2015, the EPA issued a final rule requiring all coal ash and other coal combustion residuals to be treated as a solid waste under Subtitle D of the Resource Conservation and Recovery Act for disposal in landfills and/or surface impoundments while allowing for the continued recycling of coal ash. TEP does not operate any impoundments. Under the rule, the Springerville ash landfill is classified as an existing landfill and is not subject to the lateral expansion requirements. However, TEP will incur additional costs for site preparation and monitoring at Springerville to be fully compliant with the rule. TEP’s share of the cost at Springerville is estimated to be $2 million, the majority of which is expected to be capital expenditures. TEP currently estimates its share of the costs to be $5 million at Four Corners, $3 million at Navajo, and less than $1 million at San Juan, the majority of which are expected to be capital expenditures.

See Capital Expenditures above for TEP's actual and forecasted environmental compliance costs.

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 subsequent periods. Additional information on TEP’s other significant accounting policies can be found in Note 1 of Notes to Consolidated Financial Statements in Part II, Item 8 of this

Form 10-K.

Accounting for Regulated Operations

We account for our regulated electric operations in accordance with 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 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.

As of December 31, 2016, regulatory liabilities net of regulatory assets on the balance sheet totaled $95 million. 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 in Part II, Item 8 of this Form 10-K for additional information regarding regulatory matters.

Accounting for Asset Retirement Obligations

GAAP requires us 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 regulations imposed by State and Federal regulators, 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 AROs. TEP primarily defers costs associated with its legal AROs as regulatory assets because these costs are included in depreciation rates approved for recovery by the ACC. Deferred costs are amortized over the life of the underlying asset.

TEP identified legal obligations to retire generation facilities specified in land leases for its jointly-owned Navajo and Four Corners facilities. 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 expiration of the leases. TEP also has certain environmental obligations at Luna, San Juan, Sundt and Springerville. TEP estimates that its share of the AROs to remove the Navajo and Four Corners facilities and settle the Luna, San Juan, Sundt, Gila River, and Springerville environmental obligations will be approximately $157 million at the retirement dates. Additionally, TEP entered into ground lease agreements with certain land owners for the installation of 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 $26 million at the retirement dates. No other legal obligations to retire generation plant assets have been 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 will 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 $33 million as of December 31, 2016. ARO liabilities are reported in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. See Note 3 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information regarding AROs.

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 as of December 31, 2016, represent non-legal ARO accruals, less actual removal costs incurred, net of salvage proceeds realized, and are recorded as a regulatory liabilities on the balance sheet. See Note 2 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

Pension and Other Postretirement Benefit Plan Assumptions

TEP records the underfunded amount for its pension and other postretirement obligations as a liability and a regulatory asset to reflect expected recovery of pension and other postretirement obligations through the rates charged to retail customers. As the funded status, discount rates, and actuarial facts change, the liability will vary significantly in future years. Key assumptions used include:

- discount rates used to determine obligations;
- expected returns on plan assets;
- compensation increases;

- mortality assumptions; and
- health care cost trend rates.

Discount Rates

As of December 31, 2016, TEP discounted its future pension plan obligations at 4.2% and its other postretirement plan obligations at a rate of 4.0%. The discount rate for future pension plan and other postretirement 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 2016, TEP elected to measure service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows beginning in 2016. At the end of 2015, we changed our approach to determine the service and interest cost components of pension and other postretirement benefit expense for future years. Previously, we measured service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. The use of this approach reduced 2016 service and interest cost by $4 million with a corresponding increase to regulatory assets. This change does not affect the measurement of our plan obligations nor the funded status of our plans.

See Note 8 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K.

Expected Returns on Plan Assets

To establish the expected return on assets assumption, 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. As of December 31, 2016, TEP assumed that its pension plans' assets would generate a long-term rate of return of 7%.

Compensation Increases

As of December 31, 2016, TEP reduced the rate of compensation increase to 2.75% to measure pension obligations from 3% used as of December 31, 2015.

Mortality

The RP-2014 mortality table projected with improvement scale MP-2016 with 15 year convergence and 0.75% long term rate was utilized to measure the December 31, 2016 pension obligations, whereas improvement scale MP-2015 was utilized for the December 31, 2015 measurement.

Health Care Cost Trend Rates

TEP used a current year health care cost trend rate of 7.6% in valuing its other postretirement benefit obligation as of December 31, 2016. This rate reflects both market conditions and historical experience.

Sensitivity Analysis

The table below shows the effect on TEP's 2016 expense and obligation of a 100 basis point change to its assumptions:

	Effect on Expense		Effect on Obligation	
	Increase	Decrease	Increase	Decrease
(in millions)	December 31, 2016			
Change to Pension				
Discount Rate	$(5)	$ 6	$(56)	$ 70
Long-Term Rate of Return on Plan Assets	(3)	3	N/A	N/A
Change to Other Postretirement Benefits				
Discount Rate	—	1	(7)	9
Long-Term Rate of Return on Plan Assets	—	—	N/A	N/A
Health Care Cost Trend Rate	1	(1)	7	(6)

35

In 2017, TEP will incur pension costs of approximately $11 million and other postretirement benefit costs of approximately $5 million. TEP expects to charge approximately $13 million of these costs to operations and maintenance expense and $3 million to capital. TEP expects to make pension plan contributions of $11 million in 2017. In 2017, TEP expects to make benefit payments to retirees under the retiree benefit plan of approximately $4 million and contributions to the Voluntary Employee Beneficiary Association (VEBA) trust of approximately $1 million, net of distributions.

See Note 8 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for further details regarding TEP's pension plan and other postretirement benefit plan expenses and obligations.

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 will have 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 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 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 as of December 31, 2016, 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.

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, 2016, approximately $23 million of variable rate lease debt for the Springerville Common Facilities lease had been hedged through an interest rate swap agreement through January 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, unbilled revenues increase during the spring and summer and decrease during the fall and winter. A provision for uncollectible accounts, associated with retail revenues, is recorded as a component of Operations and Maintenance 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 3 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K. 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 in Part II, Item 8 of this Form 10-K for additional information regarding depreciation rates.

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 as of our balance sheet date. TEP records income tax liabilities based on TEP's taxable income as reported in the consolidated tax return of FortisUS, Inc., a Fortis intermediate holding company (FortisUS).

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. TEP recorded no valuation allowance as of December 31, 2016. See Note 12 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements affecting TEP, refer to Note 13 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K.

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 for additional information.

Risk Management Committee

TEP has a Risk Management Committee responsible for the oversight of commodity price risk and credit risk related to wholesale energy marketing and power procurement activities. The 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. 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 $137 million in tax-exempt variable rate debt outstanding as of December 31, 2016. The outstanding debt included one series of bonds for which interest rates are reset weekly and one series of bonds for which interest rates are reset monthly. The weighted average weekly rate (including LOC fees and remarketing fees) was 1.33% in 2016 and 1.24% in 2015. The average weekly interest rate ranged from 0.93% - 1.76% in 2016 and 0.93% - 1.42% in 2015. The monthly rate is based on a percentage of an index equal to one-month LIBOR plus a credit spread. The average monthly rate was 1.01% in 2016 and 0.82% in 2015. The monthly rate ranged from 0.83% - 1.08% in 2016 and 0.79% - 0.87% in 2015.

TEP is 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 $1 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 interest rate risk associated with a portion of its Springerville Common Facilities lease debt. The notional amount of the swap is $23 million as of December 31, 2016. The notional amount of lease debt that was unhedged as of December 31, 2016 was $9 million. TEP did not have any other interest rate swaps as of December 31, 2016.

Interest Rate Swap

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

(in millions)	2016	2015	2014
Net Unrealized Gains	$ 1	$ 1	$ 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 ABR. 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 negatively affect cash flows. Declines in values could also increase the reported pension expense, negatively affecting TEP's results of operations.

Commodity and Coal Price Risk

TEP is exposed to 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.

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 generation 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 United States 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.

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 generation facilities, TEP typically uses purchased power, 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 purchased power 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 purchased power, 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, 2016, 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, TEP adjusted regulatory assets or regulatory liabilities as follows:

(in millions)	2016	2015	2014
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ 12	$ 6	$(18)

The table below displays the valuation methodologies and maturities of TEP’s power and gas derivative contracts by source of fair value:

	Unrealized Gain (Loss) of TEP’s Hedging Activities			
	Maturity 0 – 6 months	Maturity 6 – 12 months	Maturity over 1 yr.	Total Unrealized Gain (Loss)
(in millions)	December 31, 2016			
Prices Actively Quoted	$1	$ 2	$ (1)	$ 2

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 $1 million; for gas swaps, 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 fuel price risk from changes in the price of coal used to fuel its coal-fired generation facilities. This risk is mitigated through the use of long term coal supply agreements with limited price movement.

TEP's coal supply contract for Springerville Units 1 and 2 expires in 2020, at which time a new coal purchase agreement will be negotiated. TEP expects coal reserves from the Lee Ranch - El Segundo mine, which supplies Springerville Units 1 and 2, to be sufficient to supply the estimated requirements for the units' presently estimated remaining lives. The current coal price was reset in 2016 and will be subject to annual adjustments through 2020.

TEP participates in jointly-owned generation 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 new coal supply contract with WCC for San Juan, effective January 31, 2016, expires in 2022. As of December 31, 2016, TEP had contracts to purchase coal for use at the jointly-owned facilities and expected its estimated average annual cost for the next three years to be $67 million and $25 million thereafter through 2031.

See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Liquidity and Capital Resources and Note 7 of Notes to Consolidated Financial Statements in Part II, Item 8 of this Form 10-K for additional information.

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 an LOC.

TEP has entered into short-term and long-term transactions with several financial institution counterparties with terms of one month through three years. As of December 31, 2016, the credit exposure to TEP from financial institution counterparties was $3 million.

As of December 31, 2016, TEP’s total credit exposure related to its wholesale marketing and gas hedging activities was approximately $17 million. TEP had approximately $1 million of exposure to non-investment grade counterparties.

As of December 31, 2016, TEP posted no cash collateral nor LOCs as credit enhancements with its counterparties, and TEP holds approximately $6 million in collateral from its wholesale counterparties.

ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control 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, 2016. In making this assessment, management used the criteria set forth by the 2013 Committee of Sponsoring Organizations (COSO) Internal Control – Integrated Framework.

Based on management's assessment using those criteria, management has concluded that, as of December 31, 2016, 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 sheets of Tucson Electric Power Company as of December 31, 2016, and 2015, and the related consolidated statements of income, comprehensive income, changes in stockholder’s equity and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits 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 audits 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 audits 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 at December 31, 2016 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Ernst & Young LLP

Calgary, Canada

February 16, 2017

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

	Years Ended December 31,		
	2016	2015	2014
Operating Revenues			
Retail	$989,580	$1,021,543	$970,145
Wholesale	117,341	167,020	158,323
Other	128,074	117,981	141,433
Total Operating Revenues	1,234,995	1,306,544	1,269,901
Operating Expenses			
Fuel	289,862	305,559	297,537
Purchased Power	85,354	124,764	152,922
Transmission and Other PPFAC Recoverable Costs	23,781	24,798	18,179
Increase (Decrease) to Reflect PPFAC Recovery Treatment	21,064	39,787	(11,194)
Total Fuel and Purchased Power	420,061	494,908	457,444
Operations and Maintenance	353,905	345,356	378,877
Depreciation	146,097	138,093	126,520
Amortization	22,498	19,261	28,567
Taxes Other Than Income Taxes	49,303	49,623	47,805
Total Operating Expenses	991,864	1,047,241	1,039,213
Operating Income	243,131	259,303	230,688
Other Income (Deductions)			
Interest Income	111	93	208
Other Income	5,636	6,647	8,598
Other Expense	(3,019)	(2,833)	(12,735)
Appreciation (Depreciation) in Value of Investments	2,147	(142)	1,371
Total Other Income (Deductions)	4,875	3,765	(2,558)
Interest Expense			
Long-Term Debt	62,015	61,159	60,577
Capital Leases	3,356	3,994	10,249
Other Interest Expense	531	1,134	810
Interest Capitalized	(1,710)	(2,732)	(3,755)
Total Interest Expense	64,192	63,555	67,881
Income Before Income Taxes	183,814	199,513	160,249
Income Tax Expense	59,376	71,719	57,911
Net Income	$124,438	$127,794	$102,338

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

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

	Years Ended December 31,		
	2016	2015	2014
Comprehensive Income			
Net Income	$124,438	$127,794	$102,338
Other Comprehensive Income (Loss)			
Net Changes in Fair Value of Cash Flow Hedges:			
Net of Income Tax (Expense) Benefit of $(420), $(821), and $(1,140)	652	1,261	1,675
Supplemental Executive Retirement Plan Adjustments:			
Net of Income Tax (Expense) Benefit of $399, $(63), and $1,068	(643)	101	(1,725)
Total Other Comprehensive Income (Loss), Net of Tax	9	1,362	(50)
Total Comprehensive Income	$124,447	$129,156	$102,288

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

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

	Years Ended December 31,		
	2016	2015	2014
Cash Flows from Operating Activities			
Net Income	$124,438	$127,794	$102,338
Adjustments to Reconcile Net Income To Net Cash Flows from Operating Activities:			
Depreciation Expense	146,097	138,093	126,520
Amortization Expense	22,498	19,261	28,567
Amortization of Debt Issuance Costs	2,853	3,043	2,626
Use of Renewable Energy Credits for Compliance	17,618	19,731	17,818
Deferred Income Taxes	59,367	72,026	59,024
Pension and Other Postretirement Benefits Expense	15,338	18,588	13,648
Pension and Other Postretirement Benefits Funding	(13,459)	(30,682)	(14,388)
Allowance for Equity Funds Used During Construction	(4,522)	(5,352)	(6,677)
Fortis Acquisition Direct Customer Benefit	—	—	18,870
FERC Transmission Refund Payable	4,878	—	—
Changes in Current Assets and Current Liabilities:			
Accounts Receivable	7,809	(3,019)	(12,886)
Materials, Supplies, and Fuel Inventory	7,627	(8,758)	666
Regulatory Assets	(12,147)	18,002	(12,777)
Accounts Payable and Accrued Charges	14,284	(13,917)	(8,763)
Regulatory Liabilities	18,012	10,921	8,388
Other, Net	14,773	(797)	(9,311)
Net Cash Flows—Operating Activities	425,464	364,934	313,663
Cash Flows from Investing Activities			
Capital Expenditures	(250,360)	(333,841)	(323,524)
Purchase, Springerville Coal Handling Facilities Lease Assets	—	(120,312)	—
Proceeds from Sale, Springerville Coal Handling Facilities	—	23,656	—
Purchase, Springerville Unit 1 Assets	(85,000)	(45,753)	(19,608)
Purchase, Gila River Unit 3	—	—	(163,938)
Purchase Intangibles, Renewable Energy Credits	(40,949)	(29,184)	(28,334)
Contributions in Aid of Construction	3,432	4,517	15,903
Other, Net	(3,176)	(1,974)	1,863
Net Cash Flows—Investing Activities	(376,053)	(502,891)	(517,638)
Cash Flows from Financing Activities			
Proceeds from Borrowings, Revolving Credit Facilities	—	148,000	275,000
Repayments of Borrowings, Revolving Credit Facilities	—	(233,000)	(190,000)
Proceeds from Borrowings, Term Loan	—	130,000	—
Repayments of Borrowings, Term Loan	—	(130,000)	—
Proceeds from Issuance, Long-Term Debt	—	299,019	149,168
Repayments, Long-Term Debt	—	(208,600)	—
Dividends Paid to Parent	(50,000)	(50,000)	(40,000)
Payments of Capital Lease Obligations	(14,079)	(13,464)	(165,145)
Payment of Debt Issuance/Retirement Costs	(183)	(3,942)	(1,856)
Contribution from Parent	—	180,000	225,000
Other, Net	(4,871)	1,458	643
Net Cash Flows—Financing Activities	(69,133)	119,471	252,810

Net Increase (Decrease) in Cash and Cash Equivalents	(19,722)	(18,486)	48,835
Cash and Cash Equivalents, Beginning of Period	55,684	74,170	25,335
Cash and Cash Equivalents, End of Period	$35,962	$55,684	$74,170

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

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31, 2016	2015
ASSETS		
Utility Plant		
Plant in Service	$5,975,139	$5,618,435
Utility Plant Under Capital Leases	167,413	131,705
Construction Work in Progress	129,955	102,028
Total Utility Plant	6,272,507	5,852,168
Accumulated Depreciation and Amortization	(2,385,053)	(2,194,301)
Accumulated Amortization of Capital Lease Assets	(104,648)	(99,638)
Total Utility Plant, Net	3,782,806	3,558,229
Investments and Other Property	45,020	39,569
Current Assets		
Cash and Cash Equivalents	35,962	55,684
Accounts Receivable, Net	124,934	136,682
Fuel Inventory	25,887	34,600
Materials and Supplies	97,126	94,003
Regulatory Assets	56,340	51,841
Derivative Instruments	4,966	1,808
Assets Held for Sale, Net	—	21,550
Other	13,793	25,904
Total Current Assets	359,008	422,072
Regulatory and Other Assets		
Regulatory Assets	225,453	212,312
Derivative Instruments	330	430
Other	37,372	16,866
Total Regulatory and Other Assets	263,155	229,608
Total Assets	$4,449,989	$4,249,478

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

(Continued)

TUCSON ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Amounts in thousands, except share data)

	December 31, 2016	2015
CAPITALIZATION AND OTHER LIABILITIES		
Capitalization		
Common Stock Equity:		
Common Stock (No Par Value, 75,000,000 Shares Authorized, 32,139,434 Shares Outstanding as of December 31, 2016 and 2015)	$1,296,539	$1,296,539
Capital Stock Expense	(6,357)	(6,357)
Retained Earnings	273,408	189,317
Accumulated Other Comprehensive Loss	(4,555)	(4,564)
Total Common Stock Equity	1,559,035	1,474,935
Preferred Stock (No Par Value, 1,000,000 Shares Authorized, None Outstanding as of December 31, 2016 and 2015)	—	—
Capital Lease Obligations	39,267	55,324
Long-Term Debt, Net	1,453,072	1,451,720
Total Capitalization	3,051,374	2,981,979
Current Liabilities		
Current Obligations Under Capital Leases	51,765	14,114
Accounts Payable	89,797	86,274
Accrued Taxes Other than Income Taxes	37,639	37,577
Accrued Employee Expenses	29,465	27,718
Accrued Interest	14,508	14,246
Regulatory Liabilities	76,069	53,077
Customer Deposits	25,778	20,349
Derivative Instruments	2,641	12,174
Other	17,837	7,533
Total Current Liabilities	345,499	273,062
Regulatory and Other Liabilities		
Deferred Income Taxes, Net	529,148	468,024
Regulatory Liabilities	300,700	307,286
Pension and Other Postretirement Benefits	131,630	120,336
Derivative Instruments	2,629	4,067
Other	89,009	94,724
Total Regulatory and Other Liabilities	1,053,116	994,437
Commitments and Contingencies		
Total Capitalization and Other Liabilities	$4,449,989	$4,249,478

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

(Concluded)

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

	Common Stock	Capital Stock Expense	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
Balances as of December 31, 2013	$888,971	$(6,357)	$49,185	$ (5,876)	$925,923
Net Income			102,338		102,338
Other Comprehensive Loss, Net of Tax				(50)	(50)
Dividends Declared to Parent			(40,000)		(40,000)
Contribution from Parent	225,000				225,000
Other	2,568				2,568
Balances as of December 31, 2014	1,116,539	(6,357)	111,523	(5,926)	1,215,779
Net Income			127,794		127,794
Other Comprehensive Income, Net of Tax				1,362	1,362
Dividends Declared to Parent			(50,000)		(50,000)
Contribution from Parent	180,000				180,000
Balances as of December 31, 2015	1,296,539	(6,357)	189,317	(4,564)	1,474,935
Net Income			124,438		124,438
Other Comprehensive Income, Net of Tax				9	9
Dividends Declared to Parent			(50,000)		(50,000)
Adoption of ASU, Cumulative Effect Adjustment			9,653		9,653
Balances as of December 31, 2016	$1,296,539	$(6,357)	$273,408	$ (4,555)	$1,559,035

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

48

Table of Contents
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. NATURE OF OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

TEP is a regulated utility that generates, transmits, and distributes electricity to approximately 420,000 retail 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, a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis.

BASIS OF PRESENTATION

TEP's consolidated financial statements and disclosures are presented in accordance with GAAP in the United States, including specific accounting guidance for regulated operations. See Note 2 for additional information regarding regulatory matters. 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 generation and transmission facilities with both affiliated and non-affiliated entities. TEP's proportionate share of jointly owned facilities is recorded in Utility Plant on the Consolidated Balance Sheets, and its proportionate share of the operating costs associated with these facilities is included in the Consolidated Statements of Income. See Note 3 for additional information regarding Utility Plant. Certain amounts from prior periods have been reclassified to conform to the current year presentation.

Variable Interest Entities

TEP regularly reviews contracts to determine if it has a variable interest in an entity, if that entity is a Variable Interest Entity (VIE), and if it is the primary beneficiary of the VIE. The primary beneficiary is required to consolidate the VIE when the variable interest holder has: (i) the power to direct activities that most significantly impact the economic performance of the VIE; and (ii) the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE.

TEP routinely enters into long-term PPAs with various entities. Some of these entities are VIEs due to the long-term fixed price component in the agreements. These PPAs effectively transfer commodity price risk to TEP, the buyer of the power, creating a variable interest. TEP has determined it is not a primary beneficiary as it lacks the power to direct the activities that most significantly impact the economic performance of the VIEs. TEP reconsiders whether it is a primary beneficiary of the VIEs on a quarterly basis.

As of December 31, 2016, the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to its variable interests under long-term PPAs are predominantly related to working capital accounts and generally represent the amounts owed by TEP for the deliveries associated with the current billing cycle. TEP's maximum exposure to loss is limited to the cost of replacing the power if the providers do not meet the production guarantee. However, the exposure to loss is mitigated as the Company would likely recover these costs through retail customer cost recovery mechanisms.

RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

Effective January 1, 2016, TEP adopted accounting guidance that simplifies the accounting for share-based payment accounting. The guidance requires that excess tax benefits and tax deficiencies be recorded as income tax benefit or expense on the statement of income and eliminates the requirement that excess tax benefits be realized before companies can recognize them. On adoption, using the modified retrospective method of transition, TEP recorded a cumulative effect adjustment of $10 million to increase retained earnings and decrease deferred income taxes related to prior period unrecognized excess tax benefits. The impact on the income statement and the statement of cash flows were not significant. TEP elected to recognize forfeitures when they occur.

USE OF ACCOUNTING ESTIMATES

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

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

49

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

Asset Retirement Obligations

TEP has identified legal AROs related to the retirement of certain generation assets. Additionally, TEP incurred AROs related to its PV assets as a result of entering into various ground leases or easement agreements. The Company records 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, the cost of the liability is capitalized by increasing the carrying amount of the related long-lived asset. The increase in the liability due to the passage of time is recorded by recognizing accretion expense in Operations and Maintenance Expense on the Consolidated Statements of Income and the capitalized cost is depreciated over the useful life of the related asset or, when applicable, the term of the lease. TEP primarily defers costs associated with its legal AROs as regulatory assets based on the ACC approval of these costs in TEP's depreciation rates.

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

Contingencies

Reserves for specific legal proceedings are established when the likelihood of an unfavorable outcome is probable and the amount of loss can be reasonably estimated. Significant judgment is required in predicting the outcome of these suits and claims, many of which take years to complete. TEP identifies certain other legal matters where the Company believes an unfavorable outcome is reasonably possible or no estimate of possible losses can be made. All contingencies are regularly reviewed to determine whether the likelihood of loss has changed and to assess whether a reasonable estimate of the loss or range of loss can be made.

ACCOUNTING FOR REGULATED OPERATIONS

TEP applies accounting standards that recognize the economic effects of rate regulation. As a result, TEP capitalizes certain costs that would be recorded as expense or in 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 amounts 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. TEP evaluates regulatory assets each period and believes 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 for additional information regarding regulatory matters.

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

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

RESTRICTED CASH

Cash balances that are restricted regarding withdrawal or usage based on contractual or regulatory considerations are reported in Investments and Other Property on the balance sheets. Restricted cash was $7 million and $4 million as of December 31, 2016 and 2015, respectively.

50

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ALLOWANCE FOR DOUBTFUL ACCOUNTS

TEP records 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. Accounts receivable are charged-off in the period in which the receivable is deemed uncollectible. The change in the balance of the Allowance for Doubtful Accounts included in Accounts Receivable, Net on the Company's Consolidated Balance Sheets is summarized as follows:

	Years Ended December 31,		
(in millions)	2016	2015	2014
Beginning of Period	$27	$5	$ 5
Additions Charged to Cost and Expense	4	2	2
Write-offs	(3)	(3)	(2)
Provision for Springerville Unit 1, Third-Party Owners	(23)	23	—
End of Period	$5	$27	$ 5

The allowance for doubtful accounts decreased in 2016 due to the settlement and release of asserted claims between TEP and the Third-Party Owners related to Springerville Unit 1. See Note 7 for additional information regarding the settlement of the Third-Party Owners' claims.

INVENTORY

TEP values materials, supplies, and fuel inventory at the lower of weighted average cost or market. Materials and Supplies consist of generation, transmission, and distribution construction and repair materials. The majority of TEP's inventory will be recovered in Retail Rates. Handling and procurement costs (such as labor, overhead costs, and transportation costs) are capitalized as part of the cost of the inventory.

UTILITY PLANT

Utility Plant includes the business property and equipment that supports electric service, consisting primarily of generation, transmission, and distribution facilities. Utility plant is reported 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.

The cost of repairs and maintenance, including planned generation overhauls, are expensed to Operations and Maintenance Expense on the Consolidated Statements of Income as costs are incurred.

When TEP retires a unit of regulated property, accumulated depreciation is reduced 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. The capitalized interest that relates to debt is recorded as a reduction in Interest Expense on the Consolidated Statements of Income. The capitalized cost for equity funds is recorded in Other Income on the Consolidated Statements of Income.

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

	2016	2015	2014
Average AFUDC Rates	7.47%	6.12%	7.30%

Depreciation

Depreciation is recorded for owned utility plant on a group method straight-line basis at depreciation rates based on the economic lives of the assets. See Note 3 for additional information regarding Utility Plant. The ACC approves depreciation rates for all generation and distribution assets. Transmission assets are subject to the jurisdiction of the FERC. Depreciation rates are based on average useful lives and include estimates for salvage value and removal costs.

51

Below are the summarized average annual depreciation rates for all utility plant:

	2016	2015	2014
Average Annual Depreciation Rates	2.85%	2.83%	2.99%

Utility Plant Under Capital Leases

TEP finances the Springerville Common Facilities with capital leases. The capital lease expense incurred consists of Amortization Expense and Interest Expense—Capital Leases on the Consolidated Statements of Income. See Note 3 for additional information regarding Utility Plant and Note 6 for additional information related to the lease terms.

Computer Software Costs

Costs incurred to purchase and develop internal use computer software are capitalized and those costs are amortized over the estimated economic life of the product. If the software is no longer useful or impaired, the carrying value is reduced and charged to expense.

EVALUATION OF ASSETS FOR IMPAIRMENT

Long-lived assets and investments are evaluated 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

Costs to issue debt are deferred and amortized to interest expense on a straight-line basis over the life of the debt, as this approximates the effective interest method. Deferred debt issuance costs are presented in the balance sheet as a direct deduction from the carrying value of the associated debt liability. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees, and printing costs. TEP accounts for debt issuance costs related to line-of-credit arrangements as an asset.

The gains and losses on reacquired debt associated with regulated operations are deferred and amortized to interest expense over the remaining life of the original debt.

OPERATING REVENUES

Revenues related to the sale of energy are recognized when services or commodities are delivered to customers. The billing of electric 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 revenue contracts that are settled financially, TEP nets the revenue contracts with the purchased power contracts and reflects the amount in Wholesale Revenues on the Consolidated Statements of Income.

TEP recognizes monthly management fees in Other Revenues as the operator of Springerville Unit 3 on behalf of Tri-State and Springerville Unit 4 on behalf of 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 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 LFCR mechanism related to kWh sales lost due to EE Standards and distributed generation. Revenues are recognized in the period that verifiable energy savings occur. Revenue recognition related to the LFCR mechanism creates a regulatory asset until such time as the revenue is collected.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

TEP recovers actual fuel, purchased power and transmission costs through base fuel rates and a PPFAC to provide electric service to retail customers. 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 for additional information regarding regulatory matters.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAMS

The ACC's RES requires Arizona regulated 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. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC. The approved costs of carrying out this plan are recovered from retail customers through the RES surcharge until such costs are reflected in TEP's non-fuel base rates.

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. The EE Standards require increasing annual targeted retail 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 Retail Revenues on the Consolidated Statements of Income in amounts necessary to offset recognized qualifying expenditures.

RENEWABLE ENERGY CREDITS

The ACC measures compliance with the RES requirements through 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. TEP had $24 million and $8 million of RECs as of December 31, 2016 and 2015, respectively. RECs are included in Regulatory and Other Assets—Other on the Consolidated Balance Sheets. See Note 2 for additional information regarding regulatory matters.

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 the balance sheet. 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. TEP reduces deferred tax assets by a valuation allowance when, in the opinion of management, it is more likely than not 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 on the Consolidated Statements of Income.

Prior to 1990, TEP flowed through to customers certain accelerated tax benefits related to utility plant as the benefits were recognized on tax returns. Regulatory assets include income taxes recoverable through future rates, which reflects the future revenues due to TEP from customers as these tax benefits reverse. See Note 2 for additional information regarding regulatory matters.

TEP accounts 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 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 a regulatory asset. All other federal and state income tax credits are treated as a reduction to income ax expense in the year the credit arises.

TEP records income tax liabilities based on TEP's taxable income as reported in the consolidated tax return of FortisUS.

53

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

TAXES OTHER THAN INCOME TAXES

TEP acts as a conduit or collection agent for sales taxes, utility taxes, franchise fees, and regulatory assessments. Trade receivables are recorded as the Company bills customers for these taxes and assessments. Simultaneously, liabilities payable to governmental agencies are recorded in the balance sheet for these taxes and assessments. These amounts are not reflected in the income statements.

FAIR VALUE

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange, and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange. See Note 11 for additional information regarding fair value.

DERIVATIVE INSTRUMENTS

The Company uses 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 exposure to energy commodity price volatility and to hedge interest rate risk exposure. For all derivative instruments that do not meet the normal purchase or normal sale scope exception, those derivative instruments are recognized as either assets or liabilities on the Consolidated Balance Sheets and are measured 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.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not recorded at fair value and settled amounts are recognized as cost of fuel, energy and capacity on the Consolidated Statements of Income.

For derivatives designated as hedging contracts, TEP formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. Also, TEP formally documents hedging activity by transaction type and risk management strategy.

For derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as regulatory assets and liabilities. See Note 11 for additional information regarding derivative instruments.

PENSION AND OTHER POSTRETIREMENT BENEFITS

TEP sponsors noncontributory, defined benefit pension plans for substantially all employees and certain affiliate employees. Benefits are based on years of service and average compensation. The Company also provides limited health care and life insurance benefits for retirees.

The Company recognizes the underfunded status of defined benefit pension plans as a liability in the balance sheet. 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. TEP recognizes a regulatory asset to the extent these future costs are probable of recovery in the rates charged to retail customers. The Company expects to recover these costs over the estimated service lives of employees.

Additionally, TEP maintains a SERP for senior management. Changes in SERP benefit obligations are recognized as a component of AOCI.

Pension and other postretirement benefit expenses are determined by actuarial valuations based on assumptions that the Company evaluates annually. See Note 8 for additional information regarding the employee benefit plans.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 2. REGULATORY MATTERS

The ACC and the FERC each regulate portions of 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.

2017 RATE ORDER

In February 2017, the ACC issued a rate order in the rate case filed by TEP in November 2015. TEP's rate filing was based on a test year ended June 30, 2015. The 2017 Rate Order approved new rates to be effective on or before March 1, 2017.

The provisions of the 2017 Rate Order include, but are not limited to:

- a non-fuel base rate increase of $81.5 million, which includes $15 million of operating costs related to the 50.5% undivided interest in Springerville Unit 1 purchased by TEP in September 2016;
- a 7.04% return on original cost rate base, which includes a cost of equity component of 9.75% and a cost of debt component of 4.32%; and
- adoption of TEP's proposed depreciation and amortization rates, which include a reduction in the depreciable life for San Juan Unit 1.

The ACC deferred TEP's proposed changes to net metering and rate design for new DG customers to Phase 2, which is expected to begin in the second quarter of 2017. TEP cannot predict the outcome of this proceeding.

COST RECOVERY MECHANISMS

TEP has received regulatory decisions that allow for more timely recovery of certain costs through the recovery mechanisms described below.

Purchased Power and Fuel Adjustment Clause

TEP's PPFAC rate is adjusted annually each April 1st and goes into effect for the subsequent 12-month period unless modified by the ACC. The PPFAC rate includes: (i) a forward component which is calculated by taking the difference between forecasted fuel and purchased power costs and the amount of those costs established in Retail Rates; and (ii) a true-up component that reconciles the difference between actual costs and those recovered in the preceding 12-month period. The PPFAC bank balance was over-collected by $38 million and $18 million as of December 31, 2016 and 2015, respectively.

In February 2017, the ACC approved in the 2017 Rate Order a PPFAC credit to begin returning the over-collected balance to customers. The table below presents TEP's PPFAC rates approved by the ACC:

Period	Cents per kWh
March 2017 through March 2018	(0.20)
May 2016 through February 2017	0.15
April 2015 through April 2016	0.68
October 2014 through March 2015	0.50
May 2014 through September 2014	0.10
July 2013 through April 2014	(0.14)

Renewable Energy Standard

The ACC’s RES requires Arizona regulated utilities to increase their use of renewable energy each year until it represents at least 15% of their total annual retail energy requirements by 2025, with DG accounting for 30% of the annual renewable energy requirement. Arizona utilities must file an annual RES implementation plan for review and approval by the ACC.

In May 2016, the ACC approved TEP's 2016 RES implementation plan of $57 million, which was partially offset by applying approximately $9 million of previously recovered carryover funds. TEP has been approved to recover the remaining $48 million through the RES surcharge. The recovery funds the following: (i) the above market cost of renewable power purchases; (ii) previously awarded performance-based incentives for customer installed DG; (iii) depreciation and a return on certain TEP investments in company-owned solar projects; and (iv) various other program costs. TEP recognized approximately $3 million of revenue in 2016 as a return on company-owned solar projects. TEP suspended its rooftop solar program effective December 2016, but requested approval of a community solar program. The ACC is expected to consider this program in Phase 2.

In July 2016, TEP submitted its application for the 2017 RES implementation plan with a budget amount of $54 million. TEP expects to recover less than $1 million of revenue in 2017 through the RES surcharge as a return on certain company-owned solar projects. This amount reflects the return and related recovery on projects that are not included in TEP’s Retail Rates. In addition, TEP is no longer requesting recovery on company-owned solar projects through the RES mechanism. TEP expects to receive a decision on its 2017 RES implementation plan in the first half of 2017.

The percentage of retail kWh sales attributable to the 2016 RES renewable energy requirement was approximately 10%, exceeding the overall 2016 requirement of 6%. Compliance is determined through the ACC's review of TEP's annual RES implementation plan. As TEP no longer pays incentives to obtain distributed generation RECs, which are used to demonstrate compliance with the DG requirement, the ACC approved a waiver of the 2016 and 2017 residential DG requirement.

Energy Efficiency Standards

Under the EE Standards, the ACC requires electric utilities to implement cost-effective programs to reduce customers' energy consumption. The EE Standards require increasing cumulative annual targeted retail kWh savings equal to 22% by 2020. As of December 2016, TEP’s cumulative annual energy savings were approximately 12%. TEP’s compliance with the EE Standards is governed by the ACC’s approval of its annual implementation plan.

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 for regulated utilities to recover from retail customers the costs to implement DSM programs as well as an annual performance incentive. TEP records its annual DSM performance incentive for the prior calendar year in the first quarter of each year. TEP recorded $2 million in 2016, $3 million in 2015, and $2 million in 2014 related to performance, included in Retail Revenues on the Consolidated Statements of Income.

In February 2016, the ACC approved TEP's 2016 energy efficiency implementation plan, including recovery of approximately $14 million from retail customers for new and existing DSM programs. Energy savings realized through the programs will count toward meeting the EE Standards and the associated lost revenue will be partially recovered through the LFCR mechanism. TEP notified the ACC that it would not file a 2017 implementation plan and will continue its 2016 plan through the end of 2017 without change. TEP will file its 2018 implementation plan by June 1, 2017.

Lost Fixed Cost Recovery Mechanism

The LFCR mechanism provides for recovery of certain non-fuel costs that would go unrecovered due to reduced retail kWh sales as a result of implementing ACC-approved energy efficiency programs and meeting distributed generation targets. TEP records a regulatory asset and recognizes LFCR revenues when the amounts are verifiable regardless of when the lost retail kWh sales occur. TEP is required to make an annual filing with the ACC requesting recovery of the LFCR revenues recognized in the prior year. The recovery is subject to a year-over-year cap of 1% of TEP's applicable retail revenues.

TEP recorded a regulatory asset and recognized LFCR revenues of $18 million in 2016, $12 million in 2015, and $11 million in 2014. LFCR revenues are included in Retail Revenues on the Consolidated Statements of Income.

Appellate Review of Rate Decisions

In a 2015 appellate challenge to two ACC rate decisions regarding a water company, the Court of Appeals for the State of Arizona considered the issue of how the ACC should determine a utility’s “fair value,” as specified in the Arizona Constitution, in connection with authorizing recovery of costs through rate adjustors outside of a rate case. The Court reversed the ACC’s method of finding fair value in that case and raised questions concerning the relationship between the need for fair value findings and the recovery of capital and certain other utility costs through adjustors. In February 2016, the Arizona Supreme Court granted the ACC’s request for review of this decision. In

August 2016, the Supreme Court vacated the Court of Appeals decision and confirmed the ACC’s decision regarding the rate adjustor at issue.

FERC COMPLIANCE

In 2016, the FERC issued orders relating to certain late-filed TSAs, which resulted in TEP recording $22 million in time value refunds in 2016. See Note 7 for additional information related to FERC compliance associated with these transmission contracts.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

REGULATORY ASSETS AND LIABILITIES

Regulatory assets are either being collected or are expected to be collected through Retail Rates. With the exception of the leasehold improvements at Springerville Unit 1 and the coal handling facilities at Sundt, TEP does not earn a return on regulatory assets. Regulatory liabilities represent items that TEP either expects to pay to customers through billing reductions in future periods or plans to use for the purpose for which they were collected from customers. With the exception of over-recovered PPFAC costs, TEP does not pay a return on regulatory liabilities. The regulatory assets and liabilities recorded in the Consolidated Balance Sheets are summarized in the table below:

(dollars in millions)	Remaining Recovery Period (years)	December 31, 2016	2015
Regulatory Assets			
Pension and Other Postretirement Benefits (Note 8)	Various	$128	$120
Income Taxes Recoverable through Future Rates (1)	Various	29	26
Final Mine Reclamation and Retiree Health Care Costs (2)	21	27	28
Property Tax Deferrals (3)	1	23	21
Lost Fixed Cost Recovery	1	23	16
Springerville Unit 1 Leasehold Improvements (4)	7	17	21
Sundt Coal Handling Facilities (5)	Plant Life	16	—
Derivatives (Note 11)	3	2	12
Other Regulatory Assets	Various	16	20
Total Regulatory Assets		281	264
Less Current Portion	1	56	52
Total Non-Current Regulatory Assets		$225	$212
Regulatory Liabilities			
Net Cost of Removal for Interim Retirements (6)	Various	$270	$264
Purchased Power and Fuel Adjustment Clause	1	38	18
Renewable Energy Standard	Various	32	25
Deferred Investment Tax Credits (7)	Various	23	32
Other Regulatory Liabilities	Various	14	21
Total Regulatory Liabilities		377	360
Less Current Portion	1	76	53
Total Non-Current Regulatory Liabilities		$301	$307

(1) Income Taxes Recoverable through Future Rates are amortized over the life of the assets. See Note 1 and Note 12 for additional information regarding income taxes.

(2) Final Mine Reclamation and Retiree Health Care Costs represent costs associated with TEP's jointly-owned facilities at San Juan, Four Corners, and Navajo. TEP recognizes these costs at future value and is permitted to fully recover these costs through the PPFAC when paid. The majority of the final mine reclamation costs are expected to occur through 2037.

(3) Property taxes are recorded as a regulatory asset based on historical ratemaking treatment allowing regulated utilities to recover property taxes on a pay-as-you-go or cash basis. TEP records a liability to reflect the accrual for financial reporting purposes and an offsetting regulatory asset to reflect recovery for regulatory purposes. This asset is fully recovered in rates with a recovery period of approximately six months.

(4) Springerville Unit 1 Leasehold Improvements represent investments TEP made, which were previously recorded in Plant in Service on the Consolidated Balance Sheets, to ensure that the facilities continued to provide safe, reliable service to TEP's customers. TEP received ACC authorization to recover leasehold improvement costs at Springerville Unit 1 over a 10-year amortization period.

(5) In June 2014, the EPA issued a final rule that required TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continued 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. In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source, and transferred the NBV of the Sundt Coal Handling Facilities to a regulatory asset. TEP will apply excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order.

(6) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future AROs net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for transmission, distribution, generation plant, and general and intangible plant which are not yet expended.

(7) Accumulated Deferred Investment Tax Credits (ITC) represent federal energy credits generated after 2011 that are amortized over the tax life of the underlying asset.

IMPACTS OF REGULATORY ACCOUNTING

If TEP determines that it no longer meets the criteria for continued application of regulatory accounting, TEP would be required to write off its regulatory assets and liabilities related to those operations not meeting the regulatory accounting requirements. Discontinuation of regulatory accounting could have a material impact on TEP's financial statements.

NOTE 3. UTILITY PLANT AND JOINTLY-OWNED FACILITIES

UTILITY PLANT

The following table shows Plant in Service on the Consolidated Balance Sheets by major class:

(dollars in millions)	Annual Depreciation Rate (4)	Average Remaining Life in Years (4)	December 31, 2016	December 31, 2015
Plant in Service				
Generation Plant	3.31%	22	$2,866	$2,612
Transmission Plant	1.48%	32	1,024	1,008
Distribution Plant	2.08%	35	1,512	1,456
General Plant	5.48%	11	381	358
Intangible Plant, Software Costs and Other (1)	Various	Various	185	179
Plant Held for Future Use	—	—	7	5
Total Plant in Service (2)			$5,975	$5,618
Utility Plant under Capital Leases (3)			$167	$132

(1) Unamortized computer software costs were $52 million and $45 million as of December 31, 2016 and 2015, respectively. The amortization of computer software costs were $17 million in 2016, $14 million in 2015, and $17 million in 2014. Intangible Plant, Software Costs and Other primarily represents computer software. Computer software is being amortized over its expected useful life ranging from three to five years for smaller application software and its average remaining life of three years for large enterprise software.

(2) Included in Plant in Service are plant acquisition adjustments of $(139) million and $(97) million as of December 31, 2016 and 2015, respectively.

(3) In 2016, TEP committed to purchase an undivided ownership interest in the Springerville Common Facilities upon the expiration of the first lease term in December 2017. As a result of this commitment, Utility Plant Under Capital Leases increased by the present value of the purchase commitment. See Note 6 for additional information regarding the Springerville leases.

(4) The depreciation rates represent a composite of the depreciation rates of assets within each major class of utility plant. Annual Depreciation Rate and Average Remaining Life in Years are based on the 2012 depreciation study available for the major classes of Plant in Service. TEP will implement new depreciation rates effective March 1, 2017, as approved in the 2017 Rate Order.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Utility Plant Under Capital Leases

All assets included in Utility Plant Under Capital Leases are used in generation operations and amortized over the primary lease term. As of December 31, 2016, Utility Plant Under Capital Leases represent an undivided one-half interest in certain Springerville Common Facilities. See Note 6 for additional information regarding Springerville leases. The following table shows the amount of lease expense incurred for capital leases:

(in millions)	Years Ended December 31, 2016	2015	2014
Lease Expense			
Interest Expense Included in:			
Interest Expense, Capital Leases	$3	$ 4	$ 10
Operating Expenses, Fuel	—	—	1
Amortization of Capital Lease Assets Included in:			
Operating Expenses, Fuel	—	2	6
Operating Expenses, Amortization	5	6	16
Total Lease Expense	$8	$ 12	$ 33

SPRINGERVILLE ACQUISITION

In February 2016, TEP entered into an agreement for the settlement and release of asserted claims and the purchase and sale of beneficial interests in Springerville Unit 1 (Agreement). In September 2016, TEP received FERC authorization to complete the transactions contemplated in the Agreement. In accordance with the Agreement, TEP purchased the undivided interest in Springerville Unit 1 for $85 million. The purchase increased TEP's total ownership interest to 100%. See Note 7 for additional information regarding the settlement.

JOINTLY-OWNED FACILITIES

As of December 31, 2016, TEP was a participant in the following jointly-owned generation facilities and transmission systems:

(in millions)	Ownership Percentage	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Net Book Value
San Juan Units 1 and 2	50.0%	$ 496	$ 3	$ 262	$ 237
Navajo Units 1, 2, and 3	7.5%	149	4	114	39
Four Corners Units 4 and 5	7.0%	110	27	76	61
Luna Energy Facility	33.3%	55	—	2	53
Gila River Unit 3	75.0%	202	3	59	146
Gila River Common Facilities	18.8%	25	—	8	17
Springerville Coal Handling Facility [1]	83.0%	201	—	80	121
Transmission Facilities	Various	383	3	175	211
Total		$ 1,621	$ 40	$ 776	$ 885

(1) As of December 31, 2015, an undivided interest in Springerville Coal Handling Facilities was classified as Assets Held for Sale, Net. In 2016, TEP reclassified the undivided interest in the Springerville Coal Handling Facilities from Assets Held for Sale, Net to Utility Plant on the Consolidated Balance Sheets. See Note 6 for additional information regarding the Springerville Coal Handling Facilities lease interests.

As participants in these jointly-owned facilities, TEP is responsible for its share of operating and capital costs for the above facilities. The Company accounts for its share of operating expenses and utility plant costs related to these facilities using proportionate consolidation.

RETIREMENTS

San Juan

In October 2014, the EPA published a final rule approving a SIP covering BART requirements for San Juan, which includes the closure of Units 2 and 3 by December 2017. TEP is a participant in San Juan Unit 2. Given the closure of two units and the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

desire of certain participants to exit their ownership in San Juan, PNM and the other participants, including TEP, negotiated restructured ownership agreements which became effective upon the sale of SJCC stock in January 2016. As a condition of the New Mexico Public Regulatory Commission's (NMPRC) approval of the early retirement of San Juan Units 2 and 3, PNM is required to make a filing with the NMPRC in 2018 to demonstrate the ongoing economic viability of San Juan beyond 2022. Under the new restructured ownership agreements, TEP and the other remaining participants have the option to exit their remaining ownership interest in San Juan as of June 30, 2022.

As of December 31, 2016, the NBV of TEP's share in San Juan Unit 2, including construction work in progress, was $98 million. TEP will apply excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 2 for additional information regarding the 2017 Rate Order.

Sundt

In June 2014, the EPA issued a final rule that required TEP to either: (i) install, by mid-2017, SNCR and dry sorbent injection if Sundt Unit 4 continued 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. In March 2016, TEP notified the EPA of its decision to permanently eliminate coal as a fuel source, and transferred the NBV of the coal handling facilities at Sundt to a regulatory asset. As of December 31, 2016, the NBV of the coal handling facilities at Sundt was $16 million. TEP will apply excess depreciation reserves against the unrecovered NBV as approved in the 2017 Rate Order. See Note 2 for additional information regarding the 2017 Rate Order.

ASSET RETIREMENT OBLIGATIONS

The accrual of AROs is primarily related to generation and PV assets and is included in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets. The following table reconciles the beginning and ending aggregate carrying amounts of ARO accruals in the Consolidated Balance Sheets:

	December 31,	
(in millions)	2016	2015
Beginning of Period	$32	$28
Liabilities Incurred	—	4
Accretion Expense or Regulatory Deferral	2	1
Revisions to the Present Value of Estimated Cash Flows [1]	(1)	(1)
End of Period	$33	$32

(1) Primarily related to changes in expected cost estimates, in conjunction with changes of asset retirement dates of generation facilities.

NOTE 4. ACCOUNTS RECEIVABLE

The following table presents the components of Accounts Receivable, Net on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2016	2015
Customer	$74	$79
Due from Affiliates (Note 5)	9	7
Unbilled	34	39
Other [1]	13	39
Allowance for Doubtful Accounts [1]	(5)	(27)
Accounts Receivable, Net	$125	$137

(1) In 2016, Accounts Receivable—Other and Allowance for Doubtful Accounts decreased due to the settlement and release of asserted claims between TEP and the Third-Party Owners related to Springerville Unit 1. See Note 7 for additional information regarding the settlement of the Third-Party Owners' claims.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 5. RELATED PARTY TRANSACTIONS

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

The following table presents the components of related party balances included in Accounts Receivable, Net and Accounts Payable on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2016	2015
Receivables from Related Parties		
UNS Electric	$ 7	$ 6
UNS Gas	2	1
Total Due from Related Parties	$ 9	$ 7
Payables to Related Parties		
SES	$ 2	$ 2
UNS Electric	—	2
UNS Energy	—	2
Total Due to Related Parties	$ 2	$ 6

The following table presents the components of related party transactions included in the Consolidated Statements of Income:

	Years Ended December 31,		
(in millions)	2016	2015	2014
Goods and Services Provided by TEP to Affiliates			
Transmission Revenues, UNS Electric[1]	$7	$ 6	$ 1
Wholesale Revenues, UNS Electric[1]	—	2	3
Control Area Services, UNS Electric[2]	2	2	3
Common Costs, UNS Energy Affiliates[3]	14	12	13
Goods and Services Provided by Affiliates to TEP			
Wholesale Revenues, UNS Electric[1]	1	1	4
Supplemental Workforce, SES[4]	14	16	16
Corporate Services, UNS Energy[5]	7	7	14
Corporate Services, UNS Energy Affiliates[6]	4	1	1

(1) TEP and UNS Electric sell power and transmission services to each other. Wholesale power is sold at prevailing market prices while transmission services are sold at FERC approved rates through the applicable Open Access Transmission Tariff.

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

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

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

(5)

Costs for corporate services at UNS Energy 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 82% of UNS Energy's allocated costs. Corporate Services, UNS Energy includes legal and audit fees. Beginning in 2015, following the August 2014 Fortis acquisition, it includes Fortis management fees of approximately $6 million in 2016 and $5 million in 2015.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CONTRIBUTION FROM PARENT

UNS Energy made no equity contributions to TEP in 2016. TEP received contributions from UNS Energy of $180 million in 2015 and $225 million in 2014. The contributions were used to repay revolving credit loans, redeem bonds, purchase additional generation capacity, and provide additional liquidity to TEP.

DIVIDENDS PAID TO PARENT

TEP declared and paid $50 million in dividends to UNS Energy in 2016 and 2015 and $40 million in 2014.

NOTE 6. DEBT, CREDIT FACILITY, AND CAPITAL LEASE OBLIGATIONS

DEBT

Long-term debt matures more than one year from the date of the financial statements. The following table presents the components of Long-Term Debt, Net on the Consolidated Balance Sheets:

			December 31,	
(dollars in millions)	Interest Rate	Maturity Date	2016	2015
Notes				
2011 Notes	5.15%	2021	$250	$250
2012 Notes	3.85%	2023	150	150
2014 Notes	5.00%	2044	150	150
2015 Notes	3.05%	2025	300	300
Tax-Exempt Local Furnishings Bonds				
2010 Pima A	5.25%	2040	100	100
2012 Pima A	4.50%	2030	16	16
2013 Pima A	4.00%	2029	91	91
2013 Apache A [1]	1.01%	2032	100	100
Tax-Exempt Pollution Control Bonds				
2009 Pima A	4.95%	2020	80	80
2009 Coconino A	5.13%	2032	15	15
2010 Coconino A [2]	1.33%	2032	37	37
2012 Apache A	4.50%	2030	177	177
Total Long-Term Debt [3]			1,466	1,466
Less Unamortized Discount and Debt Issuance Costs			13	14
Total Long-Term Debt, Net			$1,453	$1,452

(1) The bonds are variable rate debt for which rates are reset monthly. The interest rate is calculated using a weighted average based on a percentage of an index equal to one-month LIBOR plus a credit spread. The bonds are subject to mandatory tender for purchase in 2018.

(2) The bonds are variable rate debt for which rates are reset weekly. The interest rate is calculated using a weighted average and includes LOC fees and remarketing fees. The bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019.

(3) As of December 31, 2016, all of TEP's debt is unsecured, with the exception of the 2010 Coconino A variable rate bonds, which are backed by a LOC.

DEBT ISSUANCES AND REDEMPTIONS

Fixed Rate Debt

In February 2015, TEP issued and sold $300 million aggregate principal amount of senior unsecured notes. TEP may redeem the notes prior to December 2024, with a make-whole premium plus accrued interest. On or after December 2024, TEP may redeem the notes at par plus accrued interest.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In January 2015, TEP purchased $130 million aggregate principal amount of unsecured tax-exempt Industrial Development Revenue Bonds (IDRBs) issued in June 2008 by the Industrial Development Authority (IDA) of Pima County, Arizona for the benefit of TEP. The multi-modal bonds mature in September 2029. As of December 31, 2016, TEP had not remarketed the repurchased bonds and as a result the bonds were not recorded in Long-Term Debt, Net on the Consolidated Balance Sheets.

Variable Rate Debt

In August 2015, TEP redeemed two series of variable rate tax-exempt bonds at par with an aggregate principal amount of $79 million prior to maturity. In September 2015, TEP terminated the associated LOCs issued under a revolving credit facility.

CREDIT FACILITY

In October 2015, TEP entered into a new unsecured credit agreement which replaced its previous credit agreements. The new credit facility includes: (i) a borrowing capacity of $250 million in revolving credit commitments; (ii) an LOC facility with a sublimit of $50 million; (iii) an original maturity date of October 2020; and (iv) two one-year extensions options of the facility.

In October 2016, TEP extended the final maturity date one year to October 2021 as permitted by the credit facility. Pursuant to the one-year extension option, $218 million of the commitments elected to extend to the new maturity date.

Interest rates and fees under the credit facility are based on a pricing grid tied to TEP’s credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.00% for Eurodollar loans or ABR with no spread for ABR loans. TEP expects that amounts borrowed under the credit agreement will be used for working capital and other general corporate purposes and that LOCs will be issued from time to time to support energy procurement and hedging transactions. As of December 31, 2016, TEP had no borrowings outstanding included in Current Liabilities on the Consolidated Balance Sheets. As of February 15, 2017, there was $250 million available under the revolving credit commitments and LOC facilities.

TEP's previous credit agreements provided for a total of $270 million in revolving credit commitments, LOCs supporting variable-rate, tax-exempt bonds, and a $130 million term loan commitment, with original expiration dates of November 2016 and November 2015, respectively.

2010 REIMBURSEMENT AGREEMENT

In December 2010, a $37 million LOC was issued to support certain variable rate tax-exempt bonds pursuant to the 2010 Reimbursement Agreement. The LOC has an expiration date of December 2019. Fees are payable on the aggregate outstanding amount of the LOC at a rate of 0.75% per annum based on TEP's current credit ratings.

COVENANT COMPLIANCE

Certain of TEP's credit and 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. As of December 31, 2016, TEP was in compliance with the terms of its credit and long-term debt agreements.

CAPITAL LEASE OBLIGATIONS

The following table details Capital Lease Obligations on the Consolidated Balance Sheets:

	December 31,	
(in millions)	2016	2015
Capital Lease Obligations	$ 91	$ 69
Less Current Obligations Under Capital Leases	52	14
Total Capital Lease Obligations, Non-Current	$ 39	$ 55

Springerville Unit 1 Capital Lease Purchases

In January 2015, upon expiration of the lease term, 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 the purchase, TEP owned 49.5% of Springerville Unit 1, or 192 MW of capacity.

In September 2016, TEP purchased the remaining undivided interest in Springerville Unit 1, bringing its total ownership of the assets to 100%. See Note 7 for more information regarding the settlement agreement relating to Springerville Unit 1.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Springerville Coal Handling Facilities Lease Purchase

In April 2015, upon expiration of the lease term, TEP purchased an 86.7% undivided ownership interest in the Springerville Coal Handling Facilities at the fixed purchase price of $120 million, bringing its total ownership of the assets to 100%. Upon purchase of the leased interest, TEP reduced Capital Lease Obligations on the Consolidated Balance Sheets for the purchase price.

In May 2015, SRP, the owner of Springerville Unit 4, purchased from TEP a 17.05% undivided interest in the Springerville Coal Handling Facilities for approximately $24 million.

Tri-State, the lessee of Springerville Unit 3, is obligated to either: (i) buy a 17.05% undivided interest in the facilities for approximately $24 million; or (ii) continue to make payments to TEP for the use of the facilities. Tri-State had until April 2016 to exercise its purchase option. In March 2016, Tri-State notified TEP that it was exercising its option to purchase the undivided interest in the facilities. As of December 31, 2015, the 17.05% undivided interest in the Springerville Coal Handling Facilities was classified as Assets Held for Sale, Net. However, as of December 31, 2016, TEP's management no longer believed the sale would be completed. As a result, in December 2016 Tri-State's 17.05% undivided interest in the Springerville Coal Handling Facilities was reclassified as Utility Plant from Assets Held for Sale, Net on the Consolidated Balance Sheets. In 2016, TEP recorded $1 million of catchup depreciation for the period of time the facilities were recorded in Assets Held for Sale, Net.

Springerville Common Facilities Leases

The Springerville Common Facilities Leases include: (i) one lease with a fixed purchase price of $38 million and an initial term ending December 2017; and (ii) two leases with a total fixed purchase price of $68 million and initial terms ending January 2021.

In December 2016, TEP notified the owner participant and the lessor that TEP had elected to purchase a 17.8% undivided ownership interest in the Springerville Common Facilities at the fixed purchase price of $38 million upon the expiration of the lease expiring in December 2017. Due to TEP's purchase commitment, in December 2016, TEP recorded an increase of $36 million to both Current Obligations Under Capital Leases and Utility Plant Under Capital Leases, which represents the present value of the total purchase commitment, on its Consolidated Balance Sheets.

Under the remaining two leases, TEP has options to: (i) renew the leases for periods of two or more years; or (ii) exercise the purchase options under these contracts. In addition, TEP entered into agreements with Tri-State, the lessee of Springerville Unit 3, and SRP, the owner of Springerville Unit 4, that contain the following conditions if the Common Facilities Leases are not renewed: (i) TEP will exercise the purchase options under these contracts; (ii) SRP will be obligated to buy a 14% undivided interest in the facilities; and (iii) Tri-State will be obligated to either: (a) buy a 14% undivided interest in the facilities; or (b) continue to make payments to TEP for the use of these facilities.

Springerville Common Facilities lease Interest Rate Swap

TEP entered into an interest rate swap agreement in 2006 that hedges a portion of the floating interest rate risk associated with the Springerville Common Facilities lease debt. The swap has the effect of fixing the benchmark LIBOR rate on a portion of the amortizing principal balance. The swap matures in January 2020 with interest on the lease debt payable at a swapped rate of 5.77% plus an applicable margin per the lease agreement. The lease debt outstanding as of December 31, 2016 consisted of a notional amount of $23 million on which interest was fixed by the swap and a notional amount of $9 million of debt that was not hedged. The applicable margin was 1.88% as of December 31, 2016 and 2015.

TEP recorded the interest rate swap as a cash flow hedge for financial reporting purposes. See Cash Flow Hedges in Note 11 for additional information.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

DEBT MATURITIES

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

(in millions)	Long-Term Debt[1]	Capital Lease Obligations	Total Debt Maturities[2]
2017	$ —	$ 52	$ 52
2018	100	11	111
2019	37	11	48
2020	80	18	98
2021	250	—	250
Total 2017 - 2021	467	92	559
Thereafter	999	—	999
Less: Imputed Interest	—	(1)	(1)
Total	$ 1,466	$ 91	$ 1,557

(1) $37 million of TEP's variable rate bonds are backed by an LOC issued pursuant to the 2010 Reimbursement Agreement, which expires in December 2019. Although the variable rate bond matures in 2032, the above table reflects a redemption or repurchase of such bond in 2019 as though the LOC terminates without replacement upon expiration of 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.

(2) Total long-term debt excludes $10 million of related unamortized debt issuance costs and $3 million of unamortized original issue discount.

NOTE 7. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

As of December 31, 2016, TEP had the following firm, non-cancellable, minimum purchase obligations and operating leases:

(in millions)	2017	2018	2019	2020	2021	Thereafter	Total
Fuel, Including Transportation	$100	$76	$76	$67	$43	$ 269	$631
Purchased Power	32	—	—	—	—	—	32
Transmission	18	19	19	8	4	10	78
Renewable Power Purchase Agreements	64	64	64	63	63	730	1,048
RES Performance-Based Incentives	8	8	8	8	8	59	99
Operating Leases:							
Land Easements and Rights-of-Way	1	1	1	1	2	75	81
Other	1	1	1	1	1	4	9
Total Purchase Commitments	$224	$169	$169	$148	$121	$ 1,147	$1,978

Costs for Purchased Power, Transmission, and Fuel, Including Transportation, are recoverable from customers through the PPFAC mechanism. A portion of the costs of PPAs are recoverable through the PPFAC, with the balance of costs recoverable through the RES tariff. PBIs costs are recoverable through the RES tariff. See Note 2 for information on ACC approved cost recovery mechanisms.

Fuel, Including Transportation

TEP has long-term agreements for the purchase and delivery of coal with various expiration dates between 2017 and 2031. Amounts paid under these contracts depend on actual quantities purchased and delivered. Some of these agreements include price adjustment components that will affect the future cost.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In April 2016, Peabody filed for reorganization under Chapter 11 of the Bankruptcy Code. TEP has existing agreements with Peabody to supply coal from the El Segundo and Lee Ranch mines to Springerville and from the Kayenta mine to Navajo. TEP has continued to receive its contracted coal as planned and has sufficient access to coal inventory for the near future. TEP cannot currently predict the outcome of this matter or the range of its potential impact on TEP's coal supply from Peabody.

TEP has firm transportation agreements with capacity sufficient to meet its load requirements. These agreements expire in various years between 2018 and 2040.

Purchased Power

TEP has contracts 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 with various expiration dates through the fourth quarter of 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 above are based on projected market prices as of December 31, 2016.

Transmission

TEP has agreements with other utilities to purchase transmission services over lines that are part of the Western Interconnection, a regional grid in the United States. These agreements expire in various years between 2019 and 2030.

Renewable Power Purchase Agreements

TEP enters into long-term renewable PPAs which require TEP to purchase 100% of certain renewable energy generation facilities output once commercial operation status is achieved. While TEP is not required to make payments under the agreements if power is not delivered, estimated future payments are included in the table above. These agreements expire in various years between 2030 and 2036.

RES Performance-Based Incentives

TEP has entered into REC purchase agreements to purchase the environmental attributes from retail customers with solar installations. Payments for the RECs are termed PBIs and are paid in contractually agreed-upon intervals (usually quarterly) based on metered renewable energy production. These agreements expire in various years between 2022 and 2033.

Operating Leases

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. TEP's operating lease expense totaled $2 million in 2016 and $3 million in 2015 and 2014.

CONTINGENCIES

Legal Matters

TEP is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. TEP believes such normal and routine litigation will not have a material impact on its consolidated financial results. TEP is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties, and other costs in substantial amounts on TEP and are disclosed below.

Claims Related to Springerville Generating Station Unit 1

In February 2016, TEP entered into an agreement with the Third-Party Owners for the settlement and release of asserted claims and the purchase and sale of beneficial interests in Springerville Unit 1 (Agreement). The Agreement provided that: (i) TEP would purchase the Third-Party Owners’ 50.5% undivided interest in Springerville Unit 1 for $85 million; and (ii) the Third-Party Owners would pay TEP $12.5 million for operating costs related to Springerville Unit 1 incurred on behalf of the Third-Party Owners.

In September 2016, TEP received FERC authorization to complete the transactions contemplated in the Agreement. In accordance with the Agreement, TEP purchased the undivided interest in Springerville Unit 1 for $85 million. The purchase increased TEP's total ownership interest to 100%. As also provided for in the Agreement, TEP received $12.5 million from the Third-Party Owners in full satisfaction of all previously unreimbursed operating costs, which TEP recorded in Operating Revenues—Other on the Consolidated Statements of Income. Following the purchase, all outstanding disputes, pending litigation, and arbitration proceedings between TEP and the Third-Party Owners were dismissed with prejudice.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Claims Related to San Juan Generating Station

WildEarth Guardians

In February 2013, WildEarth Guardians (WEG) filed a Petition for Review in the U.S. District Court for the District 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 the 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 the OSM administrative actions in 2008. WEG alleges various National Environmental Policy Act (NEPA) violations against the OSM, including, but not limited to, the 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 the 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 the NEPA has been demonstrated, and enjoining operations at the seven mines. SJCC intervened in this matter. SJCC was granted its motion to sever its claims from the lawsuit and transfer venue to the U.S. District Court for the District of New Mexico, where this matter is now proceeding. On July 18, 2016, the federal defendants filed a motion asking that the matter be voluntarily remanded to the OSM so the OSM may prepare a new environmental impact statement (EIS) under the NEPA regarding the impacts of the San Juan Mine mining plan approval. In August 2016, the court issued an order granting the federal defendants' motion for remand to conduct further environmental analysis and complete an EIS by August 31, 2019. The order provided that, the OSM's decision approving the mining plan will remain in effect during this process. The order further provides that if the EIS is not completed by August 31, 2019, then an order vacating the approved mine plan will become immediately effective, absent further court order. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Claims Related to Four Corners Generating Station

Endangered Species Act

On April 20, 2016, several environmental groups filed a lawsuit in the U.S. District Court for the District of Arizona against the OSM and other federal agencies under the Endangered Species Act (ESA) alleging that the OSM's reliance on the Biological Opinion and Incidental Take Statement prepared in connection with a federal environmental review were not in accordance with applicable law. The environmental review was undertaken as part of the U.S. Department of the Interior's (DOI) review process necessary to allow for the effectiveness of lease amendments and related rights-of-way renewals for Four Corners. This review process also required separate environmental impact evaluations under the NEPA and culminated in the issuance of a Record of Decision justifying the agency action extending the life of Four Corners and the adjacent Navajo mine. In addition, the lawsuit alleges that these federal agencies violated both the ESA and the NEPA in providing the federal approvals necessary to extend operations at Four Corners and the Navajo mine past July 6, 2016. The lawsuit seeks various forms of relief, including a finding that the federal defendants violated the ESA and the NEPA by issuing the Record of Decision, setting aside and remanding the Biological Opinion and Record of Decision, and enjoining the federal defendants from authorizing any elements of the Four Corners and Navajo mine pending compliance with NEPA. In July 2016, the defendants answered the complaint and APS, the operator of Four Corners, filed a motion to intervene in this matter. APS' motion was granted in August 2016. Briefing on the merits is expected to extend through May 2017. NTEC, the company that owns the Navajo Mine, filed a motion to intervene in September 2016 for the purpose of dismissing the lawsuit based on NTEC's tribal sovereign immunity. TEP cannot currently predict the outcome of this matter or the range of its potential impact.

Navajo Generating Station Lease Amendment

Navajo is located on a site that is leased from the Navajo Nation with an initial lease term through 2019. The Navajo Nation signed a lease amendment in 2013 that would extend the lease from 2019 through 2044 (2013 Navajo Lease Extension). TEP owns 7.5% of Navajo. Since 2014, TEP had accrued additional estimated lease expense of approximately $5 million based on TEP's expectation that the lease would be extended. In December 2016, TEP reversed its lease amendment liability recorded in Regulatory and Other Liabilities—Other on the Consolidated Balance Sheets as management no longer believed the 2013 Navajo Lease Extension was probable. The total lease amendment liability recorded in Regulatory and Other Liabilities—Other as of December 31, 2015, was $3 million.

Mine Reclamation at Generation Facilities Not Operated by TEP

TEP pays ongoing reclamation mine costs related to coal mines that supply generation facilities in which TEP has an ownership interest but does not operate. TEP is also liable for a portion of final mine 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 $61 million upon expiration of the coal supply agreements, which expire between 2019 and 2031. The Consolidated Balance Sheets reflect a total liability related to reclamation of $26 million and $25 million as of December 31, 2016 and 2015, respectively.

Amounts recorded for final mine reclamation are subject to various assumptions, such as estimations of reclamation costs, the dates when final reclamation will occur, and the expected inflation rate. 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 mine reclamation costs, as a component of fuel costs, 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.

Gila River Emissions Compliance

In August 2016, Gila River received a Notice of Violation from the Maricopa County Air Quality Department (MCAQD) stating the facility failed to monitor emissions during startup and to properly calibrate carbon monoxide monitors. TEP and UNS Electric own a 75% and 25%, respectively, undivided ownership interest in Gila River Unit 3. Gila River has already performed the necessary corrective actions to address the alleged violations. In December 2016, Gila River signed a settlement agreement with MCAQD resolving all alleged violations. The settlement amount was immaterial to the presentation of TEP's financial statements.

FERC Compliance

In 2015 and 2016, TEP self-reported to the FERC OE that TEP had not timely filed certain FERC-jurisdictional agreements. TEP conducted comprehensive internal reviews of its compliance with the FERC filing requirements (Compliance Reviews), and made compliance filings with the FERC Office of Energy Market Regulation. This included the filing of several TSAs entered into between 2003 and 2015 that contained certain deviations from TEP's standard form of service agreement.

In 2016, the FERC issued orders related to the late-filed TSAs, which directed TEP to issue time value refunds to the counterparties to these TSAs. As a result of the FERC Refund Orders and ongoing discussions with the OE, TEP recorded $22 million in time value refunds offsetting Wholesale Revenues on the Consolidated Statements of Income in 2016. Of the total amount recorded, TEP has paid $17 million in 2016 and accrued the remaining $5 million in Current Liabilities—Other on the Consolidated Balance Sheets as of December 31, 2016.

In June 2016, to preserve its rights, TEP petitioned the D.C. Circuit Court of Appeals to review the FERC Refund Orders. In January 2017, TEP and one of the TSA counterparties entered into a settlement agreement regarding the FERC Refund Orders. Under the agreement, the counterparty paid TEP $8 million in January 2017 and TEP dismissed the appeal with prejudice.

TEP's Compliance Reviews are still under review by the OE. The FERC could impose civil penalties on TEP as a result of the OE's review of the Compliance Reviews. At this time, TEP cannot predict the outcome or range of additional losses, if any.

Performance Guarantees

TEP has joint participation agreements with participants at Navajo, San Juan, Four Corners, and with Luna. The participants in each of the generation facilities, including TEP, have guaranteed certain performance obligations. Specifically, in the event of payment default, the non-defaulting participants have agreed to bear a proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. With the exception of Four Corners, there is no maximum potential amount of future payments (undiscounted) TEP could be required to make under the guarantees. The maximum potential amount of future payments is $250 million at Four Corners. As of December 31, 2016, there have been no such payment defaults under any of the participation agreements. The Navajo participation agreement expires in 2019, San Juan in 2022, Four Corners in 2041, and Luna in 2046.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8. EMPLOYEE BENEFIT PLANS

PENSION BENEFIT PLANS

TEP has three noncontributory, defined benefit pension plans. Benefits are based on years of service and average compensation. Two of the plans cover the majority of TEP's employees. The Company funds those plans by contributing at least the minimum amount required under Internal Revenue Service (IRS) regulations. TEP also maintains a SERP for executive management.

OTHER POSTRETIREMENT BENEFIT PLAN

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 postretirement benefits for classified employees through a VEBA. TEP contributed $2 million in 2016, $4 million in 2015, and $3 million in 2014 to the VEBA. Other postretirement benefits for unclassified employees are self-funded.

REGULATORY RECOVERY

TEP records changes in non-SERP pension plans and the other postretirement defined 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 (Loss) since SERP expense is not currently recoverable in rates.

The following table summarizes pension and other postretirement benefit amounts (excluding tax balances) included in the Consolidated Balance Sheets:

	Pension Benefits		Other Postretirement Benefits	
	December 31,			
(in millions)	2016	2015	2016	2015
Regulatory Assets	$123	$115	$5	$5
Accrued Employee Expenses	(1)	(1)	(2)	(2)
Pension and Other Postretirement Benefits	(69)	(57)	(63)	(63)
Accumulated Other Comprehensive Loss, SERP	6	5	—	—
Net Amount Recognized	$59	$62	$(60)	$(60)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

OBLIGATIONS AND FUNDED STATUS

The Company measured the actuarial present values of all defined benefit pension and other postretirement benefit obligations as of December 31, 2016 and 2015. The table below summarizes the status of all of TEP's pension and other postretirement benefit plans. All plans have projected benefit obligations in excess of the fair value of plan assets for each period presented:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
(in millions)	2016	2015	2016	2015
Change in Projected Benefit Obligation				
Beginning of Period	$394	$407	$ 78	$ 81
Actuarial (Gain) Loss	20	(22)	—	(5)
Interest Cost	15	17	2	3
Service Cost	12	12	4	4
Benefits Paid	(17)	(20)	(5)	(5)
End of Period	424	394	79	78
Change in Fair Value of Plan Assets				
Beginning of Period	336	335	13	12
Actual Return on Plan Assets	27	(3)	1	—
Benefits Paid	(17)	(20)	(5)	(5)
Employer Contributions [1]	8	24	5	6
End of Period	354	336	14	13
Funded Status at End of Period	$(70)	$(58)	$ (65)	$ (65)

[1] TEP expects to contribute $11 million to the pension plans in 2017.

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 Postretirement Benefits	
	Years Ended December 31,			
(in millions)	2016	2015	2016	2015
Net Loss	$128	$117	$ 6	$ 6
Prior Service Cost (Benefit)	—	3	(1)	(1)

The accumulated benefit obligation aggregated for all pension plans is $384 million and $355 million as of December 31, 2016 and 2015, respectively.

All three pension plans had accumulated benefit obligations in excess of plan assets as of December 31, 2016. Two of TEP's plans had accumulated benefit obligations in excess of plan assets as of December 31, 2015. The following table includes information for pension plans with accumulated benefit obligations in excess of pension plan assets:

	December 31,	
(in millions)	2016	2015
Accumulated Benefit Obligation	$384	$188
Fair Value of Plan Assets	354	169

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net periodic benefit plan cost includes the following components:

	Pension Benefits			Other Postretirement Benefits		
	Years Ended December 31,					
(in millions)	2016	2015	2014	2016	2015	2014
Service Cost	$ 12	$ 12	$ 10	$ 4	$ 4	$ 4
Interest Cost	15	17	16	2	3	3
Expected Return on Plan Assets	(23)	(23)	(21)	(1)	(1)	(1)
Amortization of Net Loss	7	7	3	—	—	—
Net Periodic Benefit Cost	$ 11	$ 13	$ 8	$ 5	$ 6	$ 6

Approximately 19% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in income.

Beginning in 2016, the Company elected to measure service and interest costs by applying the specific spot rates along the yield curve to the plans' liability cash flows. Prior to 2016, the Company measured service and interest costs for pension and other postretirement benefits utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. TEP believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of its plan obligations nor the funded status. TEP accounted for this change as a change in accounting estimate, and accordingly, accounted for it on a prospective basis.

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

	Pension Benefits						Other Postretirement Benefits		
	Regulatory Asset			AOCI			Regulatory Asset		
(in millions)	2016	2015	2014	2016	2015	2014	2016	2015	2014
Current Year Actuarial (Gain) Loss	$ 15	$ 5	$ 49	$ 1	$ —	$ 3	$ —	$ (4)	$ 5
Amortization of Net Loss	(7)	(7)	(3)	—	—	—	—	—	—
Total Recognized (Gain) Loss	$ 8	$ (2)	$ 46	$ 1	$ —	$ 3	$ —	$ (4)	$ 5

For all pension plans, TEP amortizes prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. Estimated amortization from regulatory assets into net periodic benefit cost in 2017 includes the following:

(in millions)	Pension Benefits	Other Postretirement Benefits
Net Loss	$ 7	$ —

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. 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.

TEP uses 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.

The following table includes the weighted average assumptions used to determine benefit obligations:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	2016	2015
Discount Rate	4.2%	4.5%	4.0%	4.2%
Rate of Compensation Increase	2.8%	3.0%	N/A	N/A

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table includes the weighted average assumptions used to determine net periodic benefit costs:

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	2016	2015	2014
Discount Rate, Service Cost	4.8%	4.2%	5.1%	4.6%	3.9%	4.7%
Discount Rate, Interest Cost	3.9%	4.2%	5.1%	3.4%	3.9%	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%

The following table includes the assumed health care cost trend rates:

	December 31,	
	2016	2015
Next Year	7.6%	7.6%
Ultimate Rate Assumed	4.5%	4.5%
Year Ultimate Rate is Reached	2037	2036

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 amounts:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
(in millions)	December 31, 2016	
Increase (Decrease) on Total Service and Interest Cost Components	$ 1	$ (1)
Increase (Decrease) on Other Postretirement Benefit Obligation	7	(6)

PENSION PLAN AND OTHER POSTRETIREMENT BENEFIT ASSETS

TEP calculates the fair value of plan assets on December 31, the measurement date. Asset allocations, by asset category, on the measurement date were as follows:

	Pension		Other Postretirement	
	2016	2015	2016	2015
Asset Category				
Equity Securities	49 %	49 %	60 %	60 %
Fixed Income Securities	41 %	41 %	35 %	35 %
Real Estate	8 %	8 %	2 %	2 %
Other	2 %	2 %	3 %	3 %
Total	100 %	100 %	100 %	100 %

As of December 31, 2016, the fair value of VEBA trust assets was $14 million, of which $5 million were fixed income investments and $9 million were equities. As of December 31, 2015, the fair value of VEBA trust assets was $13 million, of which $5 million were fixed income investments and $8 million were equities. The VEBA trust assets are primarily Level 2. There are no Level 3 assets in the VEBA trust.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Level 1	Level 2	Level 3	Total
(in millions)	December 31, 2016			
Asset Category				
Cash Equivalents	$1	$—	$ —	$1
Equity Securities:				
United States Large Cap	—	61	—	61
United States Small Cap	—	18	—	18
Non-United States	—	67	—	67
Global	—	28	—	28
Fixed Income	—	144	—	144
Real Estate	—	9	19	28
Private Equity	—	—	7	7
Total	$1	$327	$ 26	$354

(in millions)	December 31, 2015			
Asset Category				
Cash Equivalents	$1	$—	$ —	$1
Equity Securities:				
United States Large Cap	—	81	—	81
United States Small Cap	—	17	—	17
Non-United States	—	67	—	67
Fixed Income	—	137	—	137
Real Estate	—	8	18	26
Private Equity	—	—	7	7
Total	$1	$310	$ 25	$336

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets 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.

(in millions)	Private Equity	Real Estate	Total
Balance as of December 31, 2014	$ 7	$ 16	$ 23
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	2	3
Purchases, Sales, and Settlements	(1)	—	(1)
Balance as of December 31, 2015	7	18	25
Actual Return on Plan Assets:			
Assets Held at Reporting Date	1	1	2
Purchases, Sales, and Settlements	(1)	—	(1)
Balance as of December 31, 2016	$ 7	$ 19	$ 26

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. TEP considers 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. TEP expects 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

TEP recognizes the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. The Company recognizes 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. TEP 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 follow. Each plan allows a variance of +/- 2% from targets before funds are automatically rebalanced.

	Pension	Other Postretirement
	December 31, 2016	
Cash/Treasury Bills	—%	2%
Equity Securities:		
United States Large Cap	17%	39%
United States Small Cap	5%	5%
Non-United States Developed	15%	7%
Non-United States Emerging	4%	9%
Global Equity	5%	—%
Global Infrastructure	3%	—%
Fixed Income	42%	38%
Real Estate	8%	—%
Private Equity	1%	—%
Total	100%	100%

Pension Fund Descriptions

For each type of asset category selected by the Pension Committee, TEP's 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, TEP's investment consultant directs investments to a private equity manager that invests in third-parties' funds.

ESTIMATED FUTURE BENEFIT PAYMENTS

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

(in millions)	2017	2018	2019	2020	2021	2022-2026
Pension Benefits	$ 18	$ 19	$ 20	$ 22	$ 23	$ 128
Other Postretirement Benefits	4	5	5	6	6	32

DEFINED CONTRIBUTION PLAN

TEP offers 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. The Company matches part of a participant's contributions to the plan. TEP made matching contributions to the plan of $5 million in 2016, 2015, and 2014.

NOTE 9. SHARE-BASED COMPENSATION

2011 STOCK AND INCENTIVE PLAN

The Fortis acquisition of UNS Energy in 2014 resulted in accelerated vesting and expense recognition of all outstanding non-vested UNS Energy share-based awards issued under the UNS Energy 2011 Omnibus Stock and Incentive Plan (2011 Plan). The outstanding non-vested awards 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. In August 2014, UNS Energy settled all outstanding share-based compensation awards related to the 2011 Plan in cash.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2015 SHARE UNIT PLAN

The Human Resources and Governance Committee (Committee) of UNS Energy approved and UNS Energy's Board of Directors ratified the 2015 Share Unit Plan (Plan) effective as of January 1, 2015. Under the Plan, key employees, including executive officers of UNS Energy and its subsidiaries, may be granted long-term incentive awards of performance-based share units (PSUs) and time-based restricted share units (RSUs) annually. Each PSU and RSU granted will be valued based on one share of Fortis common stock traded on the Toronto Stock Exchange, converted to U.S. dollars. UNS Energy allocates the obligation and expense for this plan to its subsidiaries based on the Massachusetts Formula.

UNS Energy awarded PSUs and RSUs as follows:

	2016	2015
PSUs	66,974	47,776
RSUs	33,488	23,888

The awards are classified as liability awards based on the cash settlement feature. Liability awards are measured at their fair value at the end of each reporting period and will fluctuate based on the price of Fortis common stock as well as the level of achievement of the financial performance criteria. The awards are payable on the third anniversary of the grant date. TEP's allocated share of probable payout was $4 million and $2 million as of December 31, 2016 and 2015, respectively.

TEP's allocated portion of compensation expense is recognized in Operations and Maintenance Expense on the Consolidated Statements of Income. Compensation expense associated with unvested PSUs and RSUs is recognized on a straight-line basis over the minimum required service period in an amount equal to the fair value on the measurement date or each reporting period. TEP recorded $2 million and $1 million in years ended 2016 and 2015, respectively, based on its share of UNS Energy's compensation expense.

NOTE 10. SUPPLEMENTAL CASH FLOW INFORMATION

CASH TRANSACTIONS

	Years Ended December 31,		
(in millions)	2016	2015	2014
Interest, Net of Amounts Capitalized	$61	$ 65	$ 83
Income Taxes	—	—	—

NON-CASH TRANSACTIONS

Other significant 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,		
(in millions)	2016	2015	2014
Accrued Capital Expenditures	$29	$ 28	$ 29
Net Cost of Removal of Interim Retirements (1)	8	1	12
Commitment to Purchase Capital Lease Interests	36	—	109
Capital Lease Obligations (2)	—	—	1
Asset Retirement Obligations (3)	(1)	3	4

(1) The non-cash net cost of removal of interim retirements represents an accrual for future AROs that does not impact earnings.

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

(3)

The non-cash additions to AROs and related capitalized assets represent a revision of estimated asset retirement cost due to changes in timing and amount of the expected future AROs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11. FAIR VALUE MEASUREMENTS AND DERIVATIVE INSTRUMENTS

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

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.

	Level 1	Level 2	Level 3	Total
(in millions)	December 31, 2016			
Assets				
Cash Equivalents[1]	$23	$ —	$ —	$23
Restricted Cash[1]	7	—	—	7
Energy Derivative Contracts, Regulatory Recovery[2]	—	3	—	3
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	2	2
Total Assets	30	3	2	35
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(2)	(1)	(3)
Interest Rate Swap[3]	—	(2)	—	(2)
Total Liabilities	—	(4)	(1)	(5)
Net Total Assets (Liabilities)	$30	$ (1)	$ 1	$30
(in millions)	December 31, 2015			
Assets				
Cash Equivalents[1]	$33	$—	$—	$33
Restricted Cash[1]	4	—	—	4
Energy Derivative Contracts, Regulatory Recovery[2]	—	1	—	1
Energy Derivative Contracts, No Regulatory Recovery[2]	—	—	1	1
Total Assets	37	1	1	39
Liabilities				
Energy Derivative Contracts, Regulatory Recovery[2]	—	(10)	(3)	(13)
Interest Rate Swap[3]	—	(3)	—	(3)
Total Liabilities	—	(13)	(3)	(16)
Net Total Assets (Liabilities)	$37	$(12)	$(2)	$23

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

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

(3) The Interest Rate Swap is valued using an income valuation approach based on the 6-month LIBOR and is included in Derivative Instruments on the Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		Gross Amount Not Offset in the Balance Sheets		
	Gross Amount Recognized in the Balance Sheets	Counterparty Netting of Energy Contracts	Cash Collateral Received/Posted	Net Amount
(in millions)	December 31, 2016			
Derivative Assets				
Energy Derivative Contracts	$5	$ 2	$ —	$ 3
Derivative Liabilities				
Energy Derivative Contracts	(3)	(2)	—	(1)
Interest Rate Swap	(2)	—	—	(2)
(in millions)	December 31, 2015			
Derivative Assets				
Energy Derivative Contracts	$2	$1	$—	$1
Derivative Liabilities				
Energy Derivative Contracts	(13)	(1)	—	(12)
Interest Rate Swap	(3)	—	—	(3)

DERIVATIVE INSTRUMENTS

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

The Company primarily applies the market approach for recurring fair value measurements. When TEP has observable inputs for substantially the full term of the asset or liability or uses quoted prices in an inactive market, TEP categorizes the instrument in Level 2. TEP categorizes derivatives in Level 3 when an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers is used.

For both power and gas prices TEP obtains quotes from brokers, major market participants, exchanges, or industry publications and relies on its own price experience from active transactions in the market. The Company primarily uses one set of quotations each for power and for gas and then validates those prices using other sources. TEP believes 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, TEP applies adjustments based on historical price curve relationships, transmission, and line losses.

TEP estimates the fair value of gas options using a Black-Scholes-Merton option pricing model which includes inputs such as implied volatility, interest rates, and forward price curves.

TEP also considers the impact of counterparty credit risk using current and historical default and recovery rates, as well as its own credit risk using credit default swap data.

The inputs and the Company's 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. TEP reviews the assumptions underlying its price curves monthly.

Cash Flow Hedges

To mitigate the exposure to volatility in variable interest rates on debt, TEP has an interest rate swap agreement that expires in January 2020. TEP had a purchased power swap to hedge the cash flow risk associated with a long-term power supply agreement which expired in September 2015. The after-tax unrealized gains and losses on cash flow hedge activities are reported in the statement of comprehensive income. The loss expected to be reclassified to earnings within the next twelve months is estimated to be $1 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Realized losses from cash flow hedges are shown in the following table:

	Years Ended December 31,		
(in millions)	2016	2015	2014
Capital Lease Interest Expense	$ 1	$ 2	$ 2
Long-Term Debt Interest Expense	—	—	1
Purchased Power	—	1	1

As of December 31, 2016, the total notional amount of the interest rate swap was $23 million.

Energy Derivative Contracts - Regulatory Recovery

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

	Years Ended December 31,		
(in millions)	2016	2015	2014
Unrealized Net Gain (Loss) Recorded to Regulatory (Assets) Liabilities	$ 12	$ 6	$ (18)

Energy Derivative Contracts - No Regulatory Recovery

Forward contracts with long-term wholesale customers do not qualify for regulatory recovery. For those contracts that qualify as derivatives, TEP records unrealized gains and losses in the income statement, unless and until a normal purchase or normal sale election is made. The unrealized gains and losses on long-term power trading contracts are recorded in the income statement, and 10% of any gains will be shared with ratepayers through the PPFAC, as realized.

Derivative Volumes

As of December 31, 2016, TEP has energy contracts that will settle through 2019. The volumes associated with the energy contracts were as follows:

	December 31,	
	2016	2015
Power Contracts GWh	2,610	1,752
Gas Contracts BBtu	12,355	17,214

Level 3 Fair Value Measurements

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

	Valuation Approach	Fair Value of Assets	Fair Value of Liabilities	Unobservable Inputs	Range of Unobservable Input	
(in millions)	December 31, 2016					
Forward Power Contracts	Market approach	$ 2	$ (1)	Market price per MWh	$ 20.90	$ 40.00
Level 3 Energy Contracts		$ 2	$ (1)			
(in millions)	December 31, 2015					
Forward Power Contracts	Market approach	$ 1	$ (2)	Market price per MWh	$ 19.20	$ 31.35
Gas Option Contracts	Option model	—	(1)	Market price per MMbtu	$ 2.17	$ 2.69
				Gas volatility	31.0%	58.3%
Level 3 Energy Contracts		$ 1	$ (3)			

79

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(in millions)	Years Ended December 31, 2016	2015
Beginning of Period	$(2)	$(9)
Gains (Losses) Recorded [1]		
Net Regulatory Assets or Liabilities, Derivative Instruments	2	(4)
Electric Wholesale Sales	4	3
Settlements	(3)	8
End of Period	$1	$(2)

(1) Includes gains (losses) attributable to the change in unrealized gains (losses) relating to assets (liabilities) still held at the end of the period of $1 million and $(1) million for the years ended December 31, 2016 and 2015, respectively.

CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. TEP enters 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.

TEP has contractual agreements for energy procurement and hedging activities that contain certain provisions requiring TEP and its counterparties to post collateral under certain circumstances. These circumstances include: (i) exposures in excess of unsecured credit limits; (ii) credit rating downgrades; or (iii) a failure to meet certain financial ratios. In the event that such credit events were to occur, the Company, or its counterparties, would have to provide certain credit enhancements in the form of cash, a LOC, or other acceptable security to collateralize exposure beyond the allowed amounts.

TEP considers 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 then allocates the credit risk adjustment to individual contracts. TEP also considers the impact of its credit risk on instruments that are in a net liability position, after considering collateral posted, and then allocates the credit risk adjustment to all individual contracts.

Material adverse changes could trigger credit risk-related contingent features. The value of all derivative instruments in net liability positions under contracts with credit risk-related contingent features, including contracts under the normal purchase normal sale exception, was $8 million as of December 31, 2016, compared with $20 million as of December 31, 2015. As of December 31, 2016, TEP had no LOCs as credit enhancements with its counterparties. If the credit risk contingent features were triggered on December 31, 2016, TEP would have been required to post an additional $8 million of collateral of which $8 million relates to outstanding net payable balances for settled positions.

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. TEP uses the following methods and assumptions for estimating the fair value of financial instruments:

- Borrowings under revolving credit facilities approximate the fair value due to the short-term nature of these financial instruments. These items have been excluded from the table below.
- For long-term debt, TEP uses quoted market prices, when available, or calculates the present value of remaining cash flows at the balance sheet date. When calculating present value, the Company uses current market rates for bonds with similar characteristics such as credit rating and time-to-maturity. TEP considers the principal amounts of variable rate debt outstanding to be reasonable estimates of the fair value. The Company also incorporates the impact of its own credit risk using a credit default swap rate.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts. The following table includes the face value and estimated fair value of TEP's long-term debt:

	Fair Value Hierarchy	Face Value		Fair Value	
		December 31,			
(in millions)		2016	2015	2016	2015
Liabilities					
Long-Term Debt, including Current Maturities	Level 2	$1,466	$1,466	$1,472	$1,529

NOTE 12. 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,		
(in millions)	2016	2015	2014
Federal Income Tax Expense at Statutory Rate	$64	$70	$56
State Income Tax Expense, Net of Federal Deduction	6	8	7
Federal/State Tax Credits	(8)	(8)	(5)
Allowance for Equity Funds Used During Construction	(1)	(1)	(2)
Deferred Tax Asset Valuation Allowance	(2)	1	—
Other	—	2	2
Total Federal and State Income Tax Expense	$59	$72	$58

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

	Years Ended December 31,		
(in millions)	2016	2015	2014
Current Tax Expense (Benefit)			
Federal	$—	$—	$(1)
State	—	—	—
Total Current Tax Expense (Benefit)	—	—	(1)
Deferred Tax Expense (Benefit)			
Federal	60	66	54
Federal Investment Tax Credits	(6)	(6)	(4)
State	5	12	9
Total Deferred Tax Expense (Benefit)	59	72	59
Total Federal and State Income Tax Expense	$59	$72	$58

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(in millions)	December 31, 2016	2015
Gross Deferred Income Tax Assets		
Capital Lease Obligations	$35	$27
Net Operating Loss Carryforwards	129	156
Customer Advances and Contributions in Aid of Construction	20	20
Alternative Minimum Tax Credit	25	24
Accrued Postretirement Benefits	23	23
Emission Allowance Inventory	9	9
Investment Tax Credit Carryforward	32	32
Other	60	53
Total Gross Deferred Income Tax Assets	333	344
Deferred Tax Assets Valuation Allowance	—	(4)
Gross Deferred Income Tax Liabilities		
Plant, Net	(774)	(750)
Capital Lease Assets, Net	(24)	(12)
Pensions	(26)	(27)
Other	(38)	(19)
Total Gross Deferred Income Tax Liabilities	(862)	(808)
Net Deferred Income Tax Liabilities	$529	$468

TEP recorded no valuation allowance against credit and loss carryforward deferred tax assets as of December 31, 2016 and a $4 million valuation allowance against credit and loss carryforward deferred tax assets as of December 31, 2015. Management believes TEP will produce sufficient taxable income in the future to realize credit and loss carryforwards before they expire.

As of December 31, 2016, TEP had the following carryforward amounts:

(in millions)	Amount	Expiring Year
Federal Net Operating Loss	$ 364	2031-34
State Credits	10	2017-29
Alternative Minimum Tax Credit	25	None
Investment Tax Credits	32	2032-36

Uncertain Tax Positions

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

(in millions)	December 31, 2016	2015
Beginning of Period	$ 5	$ 4
Additions Based on Tax Positions Taken in the Current Year	7	1
End of Period	$ 12	$ 5

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million as of December 31, 2016 and 2015.

TEP recorded no interest expense during 2016 and 2015 related to uncertain tax positions. In addition, TEP had no interest payable and no penalties accrued as of December 31, 2016 and 2015.

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

Table of Contents
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Concluded)

NOTE 13. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS
TEP considers the applicability and impact of all accounting standard updates issued by the Financial Accounting Standards Board (FASB). The following updates have been issued, but have not yet been adopted by TEP. Updates not listed below were assessed and determined to be either not applicable or are expected to have minimal impact on the Company's consolidated financial position, results of operations, or disclosures.
REVENUE FROM CONTRACTS WITH CUSTOMERS
In May 2014, the FASB issued an accounting standard update that will eliminate the transaction and industry-specific revenue recognition guidance under current GAAP and replace it with a principles-based approach for determining revenue recognition. In July 2015, the FASB voted to defer the effective date of the revenue recognition standard by one year, and TEP is required to adopt the new guidance for annual and interim periods beginning January 1, 2018. The Company has elected not to early adopt this standard.
The revenue standard requires entities to apply the guidance retrospectively or under the modified retrospective approach by recognizing the cumulative effect of initially applying the guidance as an adjustment to the opening balance of retained earnings supplemented by additional disclosures. TEP expects to use the modified retrospective approach.
Retail and wholesale sales of energy based on regulator-approved tariff rates represent TEP’s primary sources of revenue. TEP does not expect that the adoption of this standard will have a material impact on the recognition of revenue from energy sales to retail or wholesale customers. Certain industry specific interpretative issues, including contributions in aid of construction, remain outstanding. The conclusions reached, if different than currently anticipated, could change the Company's expected method of adoption and have a material impact on the Company’s consolidated financial statements and related disclosures.
LEASES
In February 2016, the FASB issued an accounting standard update that will require the recognition of leased assets and liabilities by lessees for those leases classified as operating leases under current GAAP. The standard is effective for periods beginning January 1, 2019, and is to be applied using a modified retrospective approach with practical expedient options. Early adoption is permitted. TEP is evaluating the impact of this update to its financial statements and disclosures.
RESTRICTED CASH
In November 2016, the FASB issued an accounting standard update that will require entities to show the changes in the total of cash, cash equivalents, and restricted cash or restricted cash equivalents in the statement of cash flows. As a result, entities will no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statement of cash flows. The standard is effective for annual and interim periods beginning January 1, 2018, and is to be applied using a retrospective approach. Early adoption is permitted. TEP is evaluating the impact of this update to its financial statements and disclosures.

NOTE 14. QUARTERLY FINANCIAL DATA (UNAUDITED)
TEP's quarterly financial information is unaudited, but, in management’s opinion, includes all adjustments necessary for a fair presentation. TEP's 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.

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	2016			
Operating Revenue	$243	$ 317	$ 394	$ 281
Operating Income	12	72	122	37
Net Income (Loss)	(1)	41	72	12
	2015			

Operating Revenue	$273	$ 340	$ 409	$ 284
Operating Income	28	74	120	36
Net Income	9	38	69	12

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

TEP’s Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal 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 United States 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 as of December 31, 2016.

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 2016 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

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Pre-Approved Policies and Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. UNS Energy’s Audit and Risk Committee has adopted a policy pursuant to which audit, audit-related, tax, and other services are pre-approved by category of service. Recognizing that situations may arise where it is in the Company’s best interest for the auditor to perform services in addition to the annual audit of the Company’s financial statements, the policy sets forth guidelines and procedures with respect to approval of the four categories of service designed to achieve the continued independence of the auditor when it is retained to perform such services for UNS Energy. The policy requires the Audit and Risk Committee to be informed of each service and does not include any delegation of the Audit and Risk Committee’s responsibilities to management. The Audit and Risk Committee may delegate to the Chair of the Audit and Risk Committee the authority to grant pre-approvals of audit and non-audit services requiring Audit and Risk Committee approval where the Audit and Risk Committee Chair believes it is desirable to pre-approve such services prior to the next regularly scheduled Audit and Risk Committee meeting. The decisions of the Audit and Risk Committee Chair to pre-approve any such services from one regularly scheduled Audit Committee meeting to the next shall be reported to the Audit and Risk Committee.

Fees

The table details fees paid to Ernst and Young LLP (EY) for professional services during 2016 and 2015. The Audit and Risk Committee has considered whether the provision of services to TEP by EY, beyond those rendered in connection with their audit and review of TEP’s financial statements, is compatible with maintaining their independence as auditor.

TEP's fees for principal accountant services are as follows:

(in thousands)	2016	2015
Audit Fees	$1,244	$1,350
Audit-Related Fees	—	—
Tax Fees	100	70
All Other Fees	—	—
Total	$1,344	$1,420

Audit fees include fees for the audit of TEP’s consolidated financial statements included in TEP’s Annual Report on Form 10-K and review of financial statements included in TEP’s Quarterly Reports on Form 10-Q. Audit fees also include services provided in connection with comfort letters, consents and other services related to SEC matters, financing transactions, and statutory and regulatory audits.

Tax fees reported for 2016 and 2015 include fees for tax appeals.

All services performed by our principal accountant are approved in advance by the Audit and Risk Committee in accordance with the Audit and Risk Committee’s pre-approval policy for services provided by the Independent Registered Public Accounting Firm.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

	Page
(a) (1) Consolidated Financial Statements as of December 31, 2016 and 2015 and for Each of the Three Years in the Period Ended December 31, 2016	
Report of Independent Registered Public Accounting Firm	42
Consolidated Statements of Income	43
Consolidated Statements of Comprehensive Income	44
Consolidated Statements of Cash Flows	45
Consolidated Balance Sheets	46
Consolidated Statement of Changes in Stockholder’s Equity	48
Notes to Consolidated Financial Statements	49

(2) Financial Statement Schedule

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(3) Exhibits

Reference is made to the Exhibit Index commencing on page 89.

ITEM 16. FORM 10-K SUMMARY

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

TUCSON ELECTRIC POWER COMPANY
(Registrant)

Date: February 16, 2017 /s/ Frank P. Marino
Frank P. Marino
Vice President, Chief Financial Officer, and Director
(Principal Financial Officer and Principal Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date: February 16, 2017		/s/ David G. Hutchens* David G. Hutchens President, Chief Executive Officer, and Director (Principal Executive Officer)
Date: February 16, 2017		/s/ Frank P. Marino Frank P. Marino Vice President, Chief Financial Officer, and Director (Principal Financial Officer and Principal Accounting Officer)
Date: February 16, 2017		/s/ Todd C. Hixon* Todd C. Hixon Director
Date: February 16, 2017	By:	/s/ Frank P. Marino Frank P. Marino *As attorney-in-fact for each of the persons indicated

EXHIBIT INDEX

*2(a)	Agreement and Plan of Merger, dated as of December 11, 2013, among FortisUS Inc., Color Acquisition Sub Inc., UNS Energy Corporation and solely for purposes of Section 5.5(a) and 8.15, Fortis Inc. (Form 8-K, dated December 12, 2013, File No. 1-05924 - Exhibit 2.1).
*2(a)(1)	First Amendment to the Agreement and Plan of Merger, dated as of August 14, 2014, by and among FortisUS Inc., Color Acquisition Sub Inc. and UNS Energy Corporation (Form 8-K, dated August 14, 2014, File No. 1-05924 - Exhibit 2.2).
*3(a)	Restated Articles of Incorporation of TEP, filed with the ACC on August 11, 1994, as amended by Amendment to Article Fourth of our Restated Articles of Incorporation, filed with the ACC on May 17, 1996. (Form 10-K for the year ended December 31, 1996, File No. 1-05924 - Exhibit No 3(a)).
*3(a)(1)	TEP Articles of Amendment filed with the ACC on September 3, 2009 (Form 10-K for the year ended December 31, 2010, File No. 1-05924 - Exhibit 3(a)).
*3(b)	Bylaws of TEP, as amended as of August 12, 2015 (Form 10-Q for the quarter ended September 30, 2015, File No. 1-05924 - Exhibit 3).
*3(c)	Amendment to Articles of Incorporation of UNS Energy Corporation, creating series of Limited Voting Junior Preferred Stock (Form 8-K dated August 12, 2015, File No. 1-05924 - Exhibit 3.2).
*4(a)(1)	Indenture of Trust, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(A)).
*4(a)(2)	Loan Agreement, dated as of October 1, 2009, between The Industrial Development Authority of the County of Pima and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company San Juan Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(B)).
*4(b)(1)	Indenture of Trust, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(C)).
*4(b)(2)	Loan Agreement, dated as of October 1, 2009, between Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Revenue Bonds, 2009 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated October 13, 2009, File No. 1-05924 - Exhibit 4(D)).
*4(c)(1)	Indenture of Trust, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 Exhibit 4(a)).
*4(c)(2)	Loan Agreement, dated as of October 1, 2010, between the Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2010 Series A (Tucson Electric Power Company Project). (Form 8-K dated October 8, 2010, File No. 1-05924 - Exhibit 4(b)).

*4(d)(1)	Indenture of Trust, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and U.S. Bank Trust National Association authorizing Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(c)).

*4(d)(2)	Loan Agreement, dated as of December 1, 2010, between the Coconino County, Arizona Pollution Control Corporation and TEP relating to Pollution Control Bonds, 2010 Series A (Tucson Electric Power Company Navajo Project). (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(d)).
*4(e)(1)	Indenture of Trust, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(e)(2)	Loan Agreement, dated as of March 1, 2012, between The Industrial Development Authority of the County of Apache and TEP, relating to Pollution Control Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(f)(1)	Indenture of Trust, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(a)).
*4(f)(2)	Loan Agreement, dated as of June 1, 2012, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2012 Series A (Tucson Electric Power Company Project). (Form 8-K dated June 21, 2012, File No. 1-05924 - Exhibit 4(b)).
*4(g)(1)	Indenture of Trust, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 14, 2013, File No. 1-05924 - Exhibit 4(a)).
*4(g)(2)	Loan Agreement, dated as of March 1, 2013, between The Industrial Development Authority of the County of Pima and TEP, relating to Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Project). (Form 8-K dated March 14, 2013, File No. 1-05924 - Exhibit 4(b)).
*4(h)(1)	Indenture of Trust, dated as of November 1, 2013, between The Industrial Development Authority of the County of Apache and U.S. Bank Trust National Association, authorizing Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Springerville Project). (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(a)).
*4(h)(2)	Loan Agreement, dated as of November 1, 2013, between The Industrial Development Authority of the County of Apache and Tucson Electric Power Company, relating to Industrial Development Revenue Bonds, 2013 Series A (Tucson Electric Power Company Springerville Project). (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(b)).
*4(h)(3)	Lender Rate Mode Covenants Agreement, dated as of November 1, 2013, between Tucson Electric Power Company and STI Institutional & Government, Inc. (Form 8-K dated November 14, 2013, File No. 1-05924 - Exhibit 4(c)).
*4(h)(4)	Amendment, dated May 26, 2015, between Tucson Electric Power Company, STI Institutional & Government, Inc., and Branch Banking and Trust Company, to Lender Rate Made Covenants Agreement, dated November 1, 2013 (Form 10-Q for the quarter ended June 30, 2015, File No. 1-05924 - Exhibit 4).

*4(i)(1)	Indenture, dated November 1, 2011, between Tucson Electric Power Company and U.S. Bank National Association, as trustee, authorizing unsecured Notes (Form 8-K dated November 8, 2011, File 1-05924 - Exhibit 4.1).
*4(i)(2)	Officers Certificate, dated November 8, 2011, authorizing 5.15% Notes due 2021. (Form 8-K dated November 8, 2011, File No. 1-05924 - Exhibit 4.2).

*4(i)(3)	Officers Certificate, dated September 14, 2012, authorizing 3.85% Notes due 2023. (Form 8-K dated September 14, 2012, File No. 1-05924 - Exhibit 4.1).
*4(i)(4)	Officer's Certificate, dated March 10, 2014, authorizing 5.00% Senior Notes due 2044 (Form 8-K dated March 10, 2014, File No. 1-05924 - Exhibit 4.1).
*4(i)(5)	Officer's Certificate, dated February 27, 2015, authorizing 3.05% Senior Notes due 2025 (Form 8-K dated February 27, 2015, File No. 1-05924 - Exhibit 4(a)).
*4(j)(1)	Reimbursement Agreement, dated as of December 14, 2010, among TEP, as Borrower, the financial institutions from time to time, parties thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank. (Form 8-K dated December 17, 2010, File No. 1-05924 - Exhibit 4(a)).
*4(j)(2)	Amendment No. 1 to Reimbursement Agreement, dated as of February 11, 2014 among TEP, as Borrower, the financial institutions from time to time, parties thereto and JPMorgan Chase Bank, N.A., as Administrative Agent and as Issuing Bank (Form 10-K for the year ended December 31, 2013, File No. 1-05924 - Exhibit 4(t)(2)).
*4(k)(1)	Credit Agreement, dated as of October 15, 2015, among Tucson Electric Power Company, MUFG Union Bank, N.A. as Administrative Agent, and a group of lenders (Form 8-K dated October 15, 2015, File No. 1-05924 - Exhibit 4.1).
*10(a)(1)	Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos Resources Inc. (San Carlos) (a wholly-owned subsidiary of the Registrant) jointly and severally, as Lessee, and Wilmington Trust Company, as Trustee, as amended and supplemented. (Form 10-K for the year ended December 31, 1985, File No. 1-05924 - Exhibit 10(f)(1)).
*10(a)(2)	Lease Supplement No.1, dated December 31, 1985, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee Trustee and Co-Trustee, respectively (document filed relates to Philip Morris Credit Corporation; documents relating to IBM Credit Financing Corporation and Emerson Financing Co. are not filed but are substantially similar). (Form S-4, Registration No. 33-52860 - Exhibit 10(g)(5)).
*10(a)(3)	Amendment No. 1, dated as of December 15, 1992, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, as Lessor. (Form S-1, Registration No. 33-55732 - Exhibit 10(g)(6)).
*10(a)(4)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(8)).
*10(a)(5)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit Financing Corporation as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(9)).

*10(a)(6)	Amendment No. 2, dated as of December 1, 1999, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-K for the year ended December 31, 1999, File No. 1-05924 - Exhibit 10(b)(10)).

*10(a)(7)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(a)).
*10(a)(8)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with IBM Credit, LLC as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(b)).
*10(a)(9)	Amendment No. 3 dated as of June 1, 2003, to Lease Agreements, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-Trustee, respectively, under a Trust Agreement with Emerson Finance Co. as Owner Participant. (Form 10-Q for the quarter ended June 30, 2003, File No. 1-05924 - Exhibit 10(c)).
*10(a)(10)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Philip Morris Capital Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.1).
*10(a)(11)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Selco Service Corporation as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.2).
*10(a)(12)	Amendment No. 4, dated as of June 1, 2006, to Lease Agreement, dated as of December 1, 1985, between TEP and San Carlos, jointly and severally, as Lessee, and Wilmington Trust Company and William J. Wade, as Owner Trustee and Co-trustee, respectively, under a Trust Agreement with Emerson Finance LLC as Owner Participant. (Form 8-K dated June 12, 2006, File No. 1-05924 - Exhibit 10.3).
12	Computation of Ratio of Earnings to Fixed Charges.
21	Subsidiaries of the Registrant.
24	Power of Attorney.
31(a)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by David G. Hutchens.
31(b)	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act, by Frank P. Marino.
**32	Statements of Corporate Officers (pursuant to Section 906 of the Sarbanes-Oxley Act of 2002).
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document

101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

101.DEF XBRL Taxonomy Extension Definition Linkbase Document

* Previously filed as indicated and incorporated herein by reference.

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